ALBERTA ENERGY COMPANY LTD.

1995 ANNUAL REPORT

Discover THE "NEW AEC"

In December 1995, Alberta Energy Company Ltd. (AEC) offered, in a friendly merger transaction, $1.1 billion for all of the outstanding stock and debt of Conwest Exploration Company Limited (Conwest). The merger offer was highly successful – over 96 percent of the Conwest shares were tendered. The transaction took effect as of January 10, 1996, after which total AEC market capitalization was $2.2 billion. In this Annual Report all financial information to year-end 1995 reflects the pre-merger AEC. All future-oriented operating information is on a post-merger basis.

Conwest was a very successful oil and gas exploration company, active primarily in the West Peace River Arch. The merger creates the second largest publicly traded upstream producer on a boe reserves basis. It results in a dramatic increase in the exploration and production assets of the "new AEC" as follows:

- Exploration land increases by 56 percent
- Natural gas reserves increase by 49 percent
- Conventional oil and NGLs reserves increase by 84 percent
- Gas production grows by 55 percent
- Conventional oil and NGLs production grows by 96 percent

AEC also has investments in pipelines, natural gas storage, and gas processing which provide an additional solid income base.

TABLE OF CONTENTS

2 *1995 Milestones*

3 *Points of Interest Highlights*

4 *To Our Shareholders*

8 *Our Quest for Hydrocarbons Exploration and Production*

18 *Supplemental Information Exploration and Production*

22 *Reaching New Markets Transportation, Storage and Processing*

25 *Supplemental Information Transportation, Storage and Processing*

26 *Management Discussion and Analysis*

33 *Consolidated Financial Statements*

51 *Corporate Information*

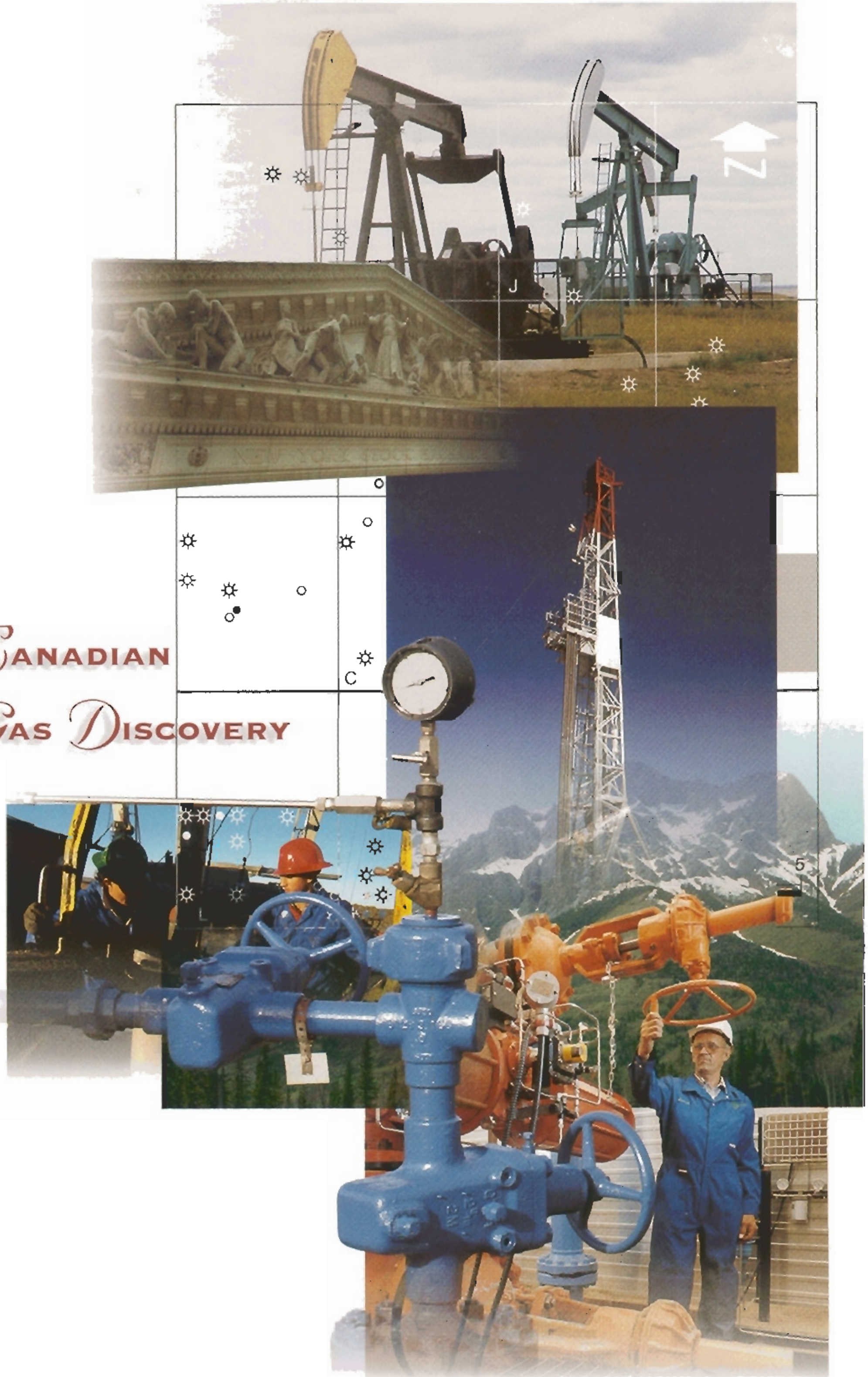
52 *Abbreviations*

STOCK TRADING SYMBOLS

Canadian Exchanges **AEC**

New York Stock Exchange **AOG**

A Major Canadian Oil and Gas Discovery



On September 21, 1995, shares of Alberta Energy Company Ltd. began trading on the New York Stock Exchange. For potential new investors, as well as existing shareholders, there is a "new AEC" to be discovered . . . a dynamic, growing Canadian oil and gas company.

1995 Milestones

Focus

➣ In late 1995, AEC initiated a $1.1 billion merger with Conwest. The merger, successfully completed in January 1996, resulted in a dramatic increase in AEC's exploration and production assets. Earlier in the year, the Company sold its final non-oil and gas business, the Forest Products Division. Net proceeds of $305 million were directed to the cash component of the Conwest merger.

Growth

➣ AEC's 1995 exploration program, the largest in the past decade, achieved a conventional production replacement of 230 percent on a proven and probable reserve basis. A total of 235 net wells were drilled – 44 exploration and 191 development – with an overall success rate of 84 percent.

➣ Conventional oil and NGLs production grew by 36 percent, mainly as a result of drilling successes at Suffield and Ogston. Total liquids production grew by 15 percent to 42,153 barrels per day – 27,823 barrels per day from Syncrude and 14,330 barrels per day of conventional oil and NGLs.

➣ The merger with Conwest results in combined gas reserves of 2.9 trillion cubic feet, conventional liquids reserves of 113 million barrels, and Syncrude reserves of 280 million barrels. Gas sales will grow to 530 million cubic feet per day in 1996; liquids sales will reach 56,000 barrels per day. Total western Canadian undeveloped lands following the merger are 2.0 million net acres.

➣ An application was filed for regulatory approval to construct the proposed Express oil pipeline from Hardisty, Alberta to Casper, Wyoming.

Financial Strength

➣ A $177.4 million decrease in long-term debt resulted in year-end debt of $384.4 million – $153.5 million in exploration and production and $230.9 million in transportation, storage and processing.

➣ The year-end exploration and production debt-to-cash flow ratio was 0.8 times. The post-merger ratio will be about 2.0 times and is expected to decline significantly by 1997.

➣ Year-end debt-to-equity ratios were 13:87 for exploration and production and 64:36 for transportation, storage and processing. The post-merger exploration and production ratio is 29:71.

Performance

➣ The price of AEC stock increased by 22 percent during the year. The stock out-performed the TSE Oil and Gas Producers Index by 7 percent. Following finalization of the Conwest merger in January, AEC had 97.9 million shares outstanding for a total market capitalization of $2.2 billion.

Points OF INTEREST

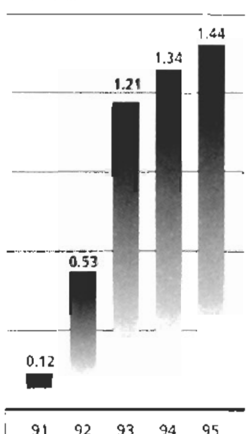
Financial Highlights	1995	1994	1993
Cash Flow from Operations ($ millions)	**270.7**	294.8	251.4
Per share ($) – Basic	**3.61**	4.07	3.52
– Fully diluted	**3.51**	3.88	3.33
Net Earnings ($ millions)	**110.2**	100.5	91.6
Per share ($) – Basic	**1.47**	1.36	1.23
– Fully diluted	**1.44**	1.34	1.21
Year-End Long-Term Debt ($ millions)	**384.4**	561.8	528.2
Exploration & Production	**153.5**	232.8	223.8
Transportation, Storage & Processing	**230.9**	229.6	207.5
Debt-to-Equity Ratio	**25:75**	35:65	35:65
Exploration & Production	**13:87**	21:79	21:79
Transportation, Storage & Processing	**64:36**	64:36	64:36
Debt-to-Cash Flow Ratio – Exploration & Production (times)	**0.8**	1.2	1.2

Operating Highlights			
Produced Natural Gas Sales (MMcfd)*	**320**	345	332
Total Liquids Sales (B/D)	**42,153**	36,820	31,041
Conventional Oil and NGLs Sales (B/D)	**14,330**	10,538	8,923
Syncrude Sales (B/D)	**27,823**	26,282	22,118
Conventional Reserve Additions (Bcfe, 10:1)	**380**	382	241

* *The difference between "sales" and "production" figures is the amount injected into AEC's storage facility.*

Earnings Per Share Increase Steadily

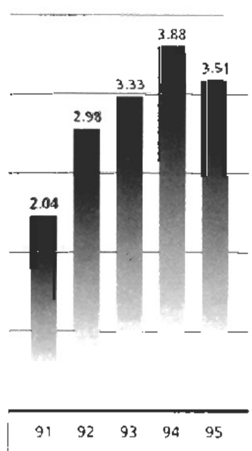
C$/share - fully diluted



Record net earnings were achieved in 1995.

Cash Flow Per Share Remains Strong

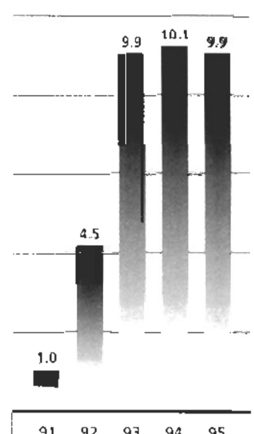
C$/share - fully diluted



Cash flow remained solid despite a dramatic drop in natural gas prices and the sale of AEC's forest products division.

Return on Equity Reflects Stability

percent



A 10 percent return on equity has been achieved for three consecutive years.

TO OUR *Shareholders*

1995 MILESTONES

In late 1995, AEC initiated the most significant transaction in its 20-year history – a $1.1 billion friendly merger with Conwest. The transaction was completed on January 10, 1996. This merger of two successful companies increases AEC's growth profile over the next several years and results in one of the strongest exploration and production companies in western Canada.

The strategic realignment of AEC from a diversified resource company into an oil and gas exploration, production, marketing and pipeline transportation company was also completed in 1995. The $305 million sale of AEC's Forest Products Division at mid-year provided the lion's share of the cash portion of the merger with Conwest.

Consistent with our counter-cyclical strategy, the Conwest merger adds substantially to AEC's solid, long-life gas reserves. As well, our unique gas storage and marketing position and the launching of AEC's largest ever exploration program will position you, as a shareholder, to profit from very substantial production growth as gas markets strengthen.

Other initiatives taken in 1995 also reflect AEC's counter-cyclical growth strategy. This is a strategy that fosters aggressive exploration and acquisition when prices are low, so that new reserves are ready to develop as prices rebound. History has shown that greater profits are achieved when investments are made at the bottom of a commodity price cycle rather than at the top.

AEC conducted its most active drilling program in ten years and moved aggressively to add 654,000 net acres of exploration land at half the per-acre cost of land acquired the previous year. Proven and probable conventional reserves additions totaled 230 percent of production, making 1995 the sixth consecutive year in which reserves grew more than production. A considerable investment in exploration land and seismic data positions AEC to conduct an even larger exploration program in 1996.

In response to higher oil prices, AEC increased its oil and natural gas liquids production in 1995, bringing average compound growth in liquids production since 1991 to 16 percent. The outlook is for continued growth in conventional and Syncrude production, with further upside potential from Argentina as well as a very promising new heavy oil recovery technology at Primrose.

Because of low gas prices, AEC delayed development of new natural gas reserves and stored a portion of production in its natural gas storage facility at Suffield. Natural gas prices were depressed in Canada due principally to inadequate export capacity to the United States. AEC expects this situation to improve gradually over the next year and to change substantially in 1997.

Further progress was made in positioning the Company for profitable growth in transportation and processing. A major new 45 percent-owned natural gas liquids processing plant is scheduled for start-up in late 1996. The gas storage facility at AECO C, Canada's dominant natural gas storage and trading hub, was further expanded in 1995, and progress was made to secure new gas storage in the United States. The proposed Express oil export pipeline, in which AEC is a 50 percent participant, is completing National Energy Board regulatory hearings and is poised to double the size of AEC's pipeline investments in 1996.

DISCOVER AEC

The new AEC is one of the largest oil and gas companies in western Canada.

The merger of AEC and Conwest assets and people provides significant potential for future growth.

The price of your AEC shares grew by 22 percent during the year, out-performing the Toronto Stock Exchange Oil and Gas Producers Index. The growing potential of AEC has translated to a 40 percent increase in our leading cash flow multiple to 5.9 times at year-end. Another major milestone in our twentieth year was the listing of AEC's common shares on the New York Stock Exchange. This is a first step in broadening AEC's international shareholder base and increasing the stock's trading liquidity. We are already seeing results, in that major New York investment houses are now providing their clients with investment analyses on AEC. As well, the new post-merger AEC is one of the most liquid Canadian upstream oil and gas stocks. Since the January 10 completion of the Conwest merger, the stock has traded an average of about 495,000 shares per day or about 10 percent of the Company's total market value of $2.2 billion.

A new Results-Based Compensation system was initiated which provides employees with direct AEC share and cash incentives for achieving or exceeding specific corporate and personal objectives. AEC employees focus on the shareholder because they are shareholders.

Throughout this Annual Report you will see an increase in financial and operating disclosure from previous years. The balance sheet and other financial information also show more clearly the two separate capital structures, consistent with industry norms for each of Exploration and Production (E&P) and Transportation, Storage and Processing (TSP). The use of independent capital structures for AEC's two areas of oil and gas investment helps AEC to maximize its return on investment while facilitating access to growth capital.

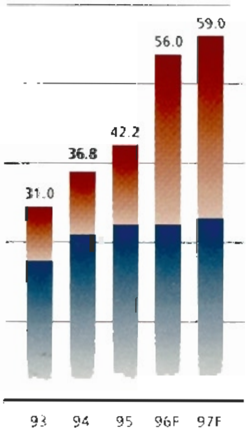
THE NEW AEC

The new AEC has the second largest oil and gas reserves position of publicly traded Canadian upstream companies on a barrel of oil equivalent basis. Gas reserves total 2.9 trillion cubic feet with a 1996 expected life index of 15 years. The merger with Conwest brings together two complementary western Canadian exploration programs. Combined exploration landholdings of 2.0 million net acres are estimated to grow to more than 2.5 million net acres by year-end 1996. Combined 1996 gas sales are estimated to be 530 million cubic feet per day, growing to 600 million cubic feet per day in 1997. The efficient utilization of Conwest tax pools, combined with higher levels of exploration and development expenditures, should defer AEC's cash tax horizon for at least three years.

Conwest's 1995 results are indicative of the strengths brought to the new AEC. Proven and probable reserves replacement was 545 percent on a billion cubic feet equivalent basis. Natural gas production grew by 32 percent to an average 80 MMcfd while liquids production increased by 15 percent. By year-end, production had grown to 170 MMcfd of gas and 9,500 B/D of oil and NGLs. Conwest acquired 238,000 net acres of land, bringing its total year-end exploration properties to 730,000 net acres. Conwest's three-year finding and development cost was $0.50/Mcfe on a proven and probable reserve basis and $0.71/Mcfe on a proven basis. The cost reflects an $80 million investment in a 150 MMcfd state-of-the-art sour gas plant and gathering system at Sexsmith in the West Peace River Arch, which was commissioned in the fourth quarter. These are but a few highlights of another year of accomplishment for the people of Conwest. We are proud to have them on board and I know that their talents and ideas will complement those of our own employees to add value to the new AEC.

Growing Oil and NGL Sales

thousand barrels per day



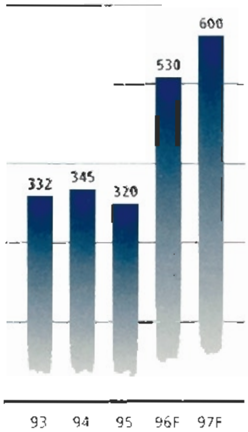
Oil sales will continue to grow as the new AEC has become a more balanced oil and gas producer.

Conventional Liquids

Syncrude

Growing Natural Gas Sales

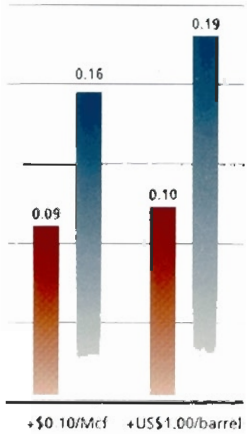
million cubic feet per day



Although gas production was a record 356 MMcfd, AEC restricted sales to 320 MMcfd in 1995 due to depressed prices. Surplus gas was injected into storage for subsequent sale at higher prices.

Commodity Price Upside Potential

dollars per share - 1996 sensitivities



The Conwest merger nearly doubled the potential growth in cash flow per share resulting from higher oil and gas prices.

AEC Pre-Merger

AEC Post-Merger

NEW HORIZONS

The major challenge facing the new, larger AEC is to sustain top quartile growth in shareholder value. This will be done by creating and growing, profitably, a group of smaller business units. Each of these entrepreneurial units will have a high degree of autonomy and accountability for specific financial, reserve, production and asset value added targets. There will be three western Canadian exploration and production business units, each of which would easily qualify in its own right as a "senior producer" in reserves, production, and capital programs. A fourth business unit will contain AEC's international activities, most notably in Argentina, and its Syncrude investment. The remaining business units consist of AEC's pipelines and gas processing operations and AEC's industry leading position in marketing and gas storage. Each of these business units will contain the required support staff such as financial, accounting, computer technology and human resources. The corporate head office will be kept as small and efficient as possible.

I am pleased to note that Conwest's two key exploration and production executives, John Stephure and Colin Coolican, will be leading the team of Conwest people into the merged company to work with AEC's team and create the new, stronger AEC force. Oilpatch mergers have typically involved a successful company taking over a weaker company, downsizing staff and imposing one company's "culture" on the other. In complete contrast, the AEC-Conwest merger is the combination of two successful companies using operating, asset, tax and people synergies to create an even stronger, more successful company.

We are striving to handle our merger process differently, and we are taking the time to do it right. Having said that, it's also important that we move forward aggressively. The newly organized business units will be staffed and operational by no later than May 1, 1996.

MORE DISCOVERIES

AEC looks to the future with tremendous confidence. Our outlook for growth in AEC's western Canadian production is unprecedented, and Argentina offers longer-term potential. Unique, AEC-initiated projects in pipelines, gas storage and marketing will provide an expanding solid base of non-commodity cash flow. I believe that the new AEC offers investors a combination of extraordinary assets and talented people, with great potential.

A thank you, and a welcome, to AEC Directors. AEC has a very capable Board of Directors who have provided outstanding corporate governance through a period of great challenge and change. On behalf of the Board and Management, I thank Harry Tims and Dick Whittall, who will be retiring at the April 1996 Annual Meeting, for their substantial contributions during a combined total of more than 28 years on AEC's Board. And a warm welcome to John Lamacraft, former Conwest CEO, to our Board. We look forward to the advice and direction from two other Conwest Directors, Martin Connell and Harley Hotchkiss, who will stand for election at the AEC Annual Meeting.

Finally, a thank you to the team of people – now totalling 780 – from AEC and Conwest for their patience, understanding and enthusiastic participation during this period of reorganization enroute to increasing shareholder value.

Gwyn Morgan

President and Chief Executive Officer
February 9, 1996

OUR *Quest* FOR HYDROCARBONS

EXPLORATION AND PRODUCTION

WESTERN CANADIAN BUSINESS ENVIRONMENT

The average industry natural gas price fell by about 30 percent in 1995, and the industry responded by decreasing gas-related drilling by approximately the same percentage. This reduced activity was offset by a 35 percent increase in oil drilling, as Canadian light oil prices were up by 10 percent. Land sale activity remained flat during 1995, while costs per acre were down about 40 percent. Interest rates were up, while the exchange rate on the Canadian dollar continued to fluctuate. The industry experienced ongoing rationalization and consolidation through $8 billion in mergers and acquisitions, as companies sought to maximize competitive advantages, synergies and economies of scale in key exploration and production areas. AEC continued its counter-cyclical investment strategy to take advantage of the opportunities available within this business environment.

1995 MILESTONES

- AEC conducted its most active exploration and development drilling program in the last ten years — a total of 235 net wells were drilled with an overall success rate of 84 percent.
- Total E&P capital expenditures, excluding acquisitions, increased by 7 percent to $183.6 million.
- Proven reserve additions of 192 Bcfe reflected a production replacement rate of 116 percent. Probable reserves increased by 188 Bcfe, providing a long-term opportunity to increase proven reserves.
- An aggressive land acquisition strategy resulted in the purchase of 654,000 net acres at an average cost of $48 per acre. These acquisitions, combined with the disposition of 250,000 acres of non-core properties, brought year-end undeveloped properties in western Canada to 1.3 million net acres.

- Natural gas production increased to a record 356 MMcfd. Due to the decline in gas prices, AEC restricted 1995 natural gas sales to an average 320 MMcfd, injecting the surplus production into its storage facility.
- Both conventional and Syncrude oil production were at record levels in 1995. Western Canadian conventional liquids production grew by 29 percent, mainly as a result of successful drilling at Suffield and the impact of 1994 drilling at Ogston. Syncrude production net to AEC increased by 6 percent. Total liquids production was 42,153 B/D.
- Three-year finding and development costs for the period 1993-95 were $0.53/Mcfe on a proven and probable reserve basis and $0.81/Mcfe on a proven basis. The 1992-94 results were $0.52/Mcfe on a proven and probable basis and $0.68/Mcfe on a proven basis. Costs for 1995 were up due to the Company's efforts to provide strategic positioning for future exploration through increased expenditures for land acquisition and pre-drilling exploration activities on deeper, larger targets. The Company also deferred natural gas reserve development and reallocated capital to accelerate growth in oil production to capture higher oil net backs.
- AEC continued to be a low-cost operator. Produced gas operating expenses were sustained at $0.27/Mcf, and conventional oil operating expenses were reduced to $3.47/bbl from $3.87/bbl in 1994.

DISCOVER AEC

Aggressive counter-cyclical investment strategies

Dominant E&P position in focus areas

Steadily growing reserves and production

Low operating costs

Extensive concentrated land base

Exploration excellence

Two-thirds of investment to gas

Conventional Exploration and Production Focus Areas

AEC and Conwest each had the same key objectives in their exploration and production strategies. These can be summarized as follows:

- Dominate exploration, development and gas processing in focus areas
- Achieve solid growth in reserves and production
- Direct approximately two-thirds of investment to natural gas projects
- Achieve full-cycle economic profits
- Grow through exploration and selective reserve acquisitions
- Build extensive, concentrated land bases
- Maintain low operating costs

Being a dominant player in core focus areas is fundamental to competitive advantage. Focused, capable technical and operating teams, along with asset dominance, are key elements of the technical advantage that both AEC and Conwest used in building successful companies. Extensive land blocks, large and efficient production facilities, and high working interests allow a company to minimize both its operating and general and administrative costs and to control the timing of reserves development in order to maximize net backs and full-cycle economics. AEC and Conwest are dominant players in their key exploration and production focus areas.

The new AEC has an average working interest of 80 percent in its gas production and 70 percent in its conventional oil and NGLs production. The Company also operates approximately 85 percent of its own production compared with an industry norm of 65 percent. The Company uses a multi-disciplinary team approach which emphasizes technical excellence. The new AEC has, on a combined basis, one of the largest, most concentrated land bases in the Canadian oil and gas business. It has over 4.7 million net acres of which 2.0 million net acres are undeveloped exploration properties.

West Peace River Arch

The West Peace River Arch (WPRA) is the key area of overlap and complementary operations between AEC and Conwest. It is a multi-zone, liquids-rich natural gas exploration and production area. AEC's expertise had been focused principally on the Doig and Halfway trends. During 1995 AEC gas production in this region averaged 80 MMcfd, up from 68 MMcfd in 1994, while oil and NGLs production grew to 2,466 B/D from 1,800 B/D. Conwest has been the preeminent Montney explorer in the region since 1991. Conwest's new Sexsmith sour gas and liquids plant was completed on budget in October 1995 and is operating near design capacity. The Montney, Halfway, Doig and other zones have further substantial exploration and development potential. Conwest's 1995 WPRA production averaged 44 MMcfd of gas and 1,940 B/D of oil and NGLs. Year-end exit rates grew to 130 MMcfd and 3,518 B/D. On a combined basis the new AEC's production from the WPRA region is anticipated to be 290 MMcfd and 12,900 B/D in 1996.

Finding and Development Costs Three-Year Average

$/thousand cubic feet of gas equivalent (10:1) proven and probable

Three-year finding and development costs remain competitive. Costs increased in 1995, as AEC pursued a counter-cyclical land acquisition strategy to position itself for future growth in exploration and development.

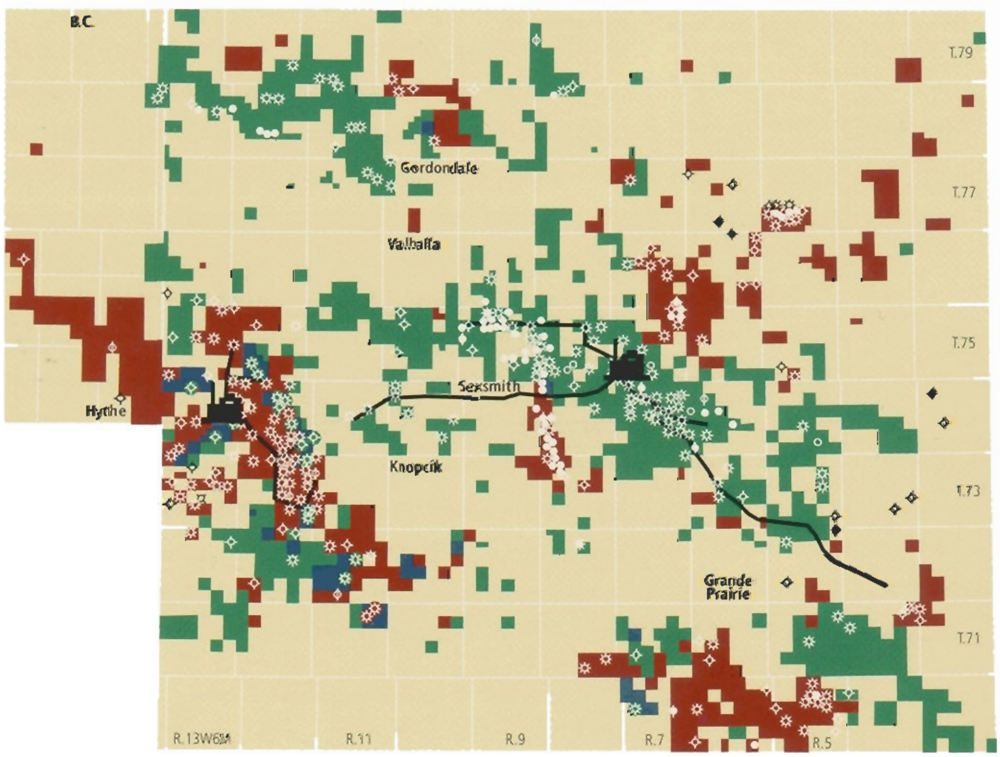
Finding and Development Costs

$/barrel of oil equivalent

	AEC			Conwest
Proven	*91-93*	*92-94*	*93-95*	*93-95*
6:1	3.90	4.75	5.70	4.85
10:1	6.10	6.80	8.15	7.05
Proven and Probable				
6:1	3.49	3.61	3.87	3.39
10:1	5.42	5.17	5.30	5.02

In the Hythe/Sexsmith/Valhalla/Knopcik area of the WPRA, the post-merger exploration, production and sour gas processing assets of the new AEC make it an important player in the area. The new 62 percent-owned Sexsmith plant will reach its licensed capacity of 210 MMcfd by the second quarter of 1996. AEC operates and owns 50 percent of the 130 MMcfd Hythe sour gas plant, the second largest facility in the area.

Hythe/Sexsmith/Valhalla/Knopcik



The combined assets in this part of the WPRA are landholdings of 750,000 net acres and proven and probable reserves of 850 Bcf of gas and 30 MMBLS of oil and NGLs. These assets on their own would qualify as a "senior" Canadian oil and gas company and will lead to additional opportunities for growth and rationalization.

In the Bigstone/Berland River area of the WPRA the Bigstone West gas plant, in which AEC has a 34 percent interest, completed its first full year of operation. AEC production in this area averaged 23 MMcfd and 712 B/D in 1995.

East Peace River Arch

The East Peace River Arch is AEC's main conventional light oil area. Total oil reserves assigned to the area at year-end 1995 were 15 MMBLS. Total 1995 production grew to an average 5,361 B/D from 3,917 B/D in 1994.

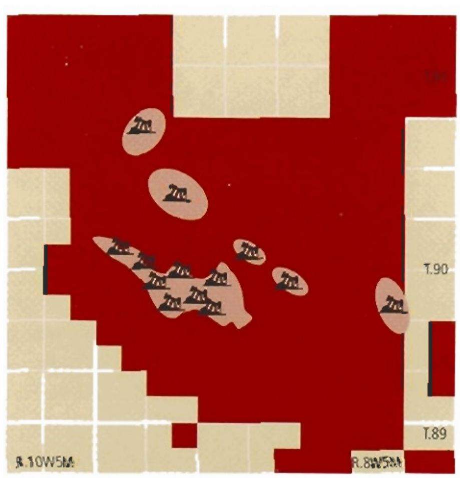
Since the Company's major discovery at Ogston in 1994, five smaller pools have been discovered. At year-end 1995, total proven and probable reserves assigned to the Ogston area were 9.5 MMBLS. Production averaged 2,867 B/D last year, up from 1,158 B/D in 1994, with operating costs of $1.40/bbl. Plans for 1996 include the drilling of two Granite Wash development wells and six exploratory wells along the trend.

Northwest Shallow Gas

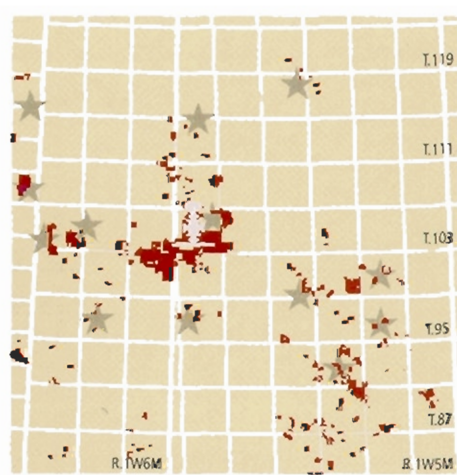
This new shallow gas play is destined to be another core area for AEC. The Company has extensive expertise in shallow gas development and production garnered during its twenty years of successful operations at Suffield and Primrose. The Stealth acquisition in 1994 established an AEC production centre in the Boyer area. This has become an exploration and production hub, around which 409,000 acres were acquired during 1995. This brings AEC's total land position in the area to 1.1 million net acres, about 50 percent of which is undeveloped property. More than 65 exploration and development drilling locations have been identified, which will be pursued during 1996.

During 1995, 54 net successful exploration and development wells were drilled. A total of 67 Bcf of natural gas reserves was added through drilling and acquisitions, bringing total proven and probable reserves in the Northwest Shallow Gas area to 210 Bcf. Restricted production from Boyer was 16 MMcfd during 1995, with operating costs of $0.46/Mcf.

Ogston



Northwest Shallow Gas



East Central Alberta

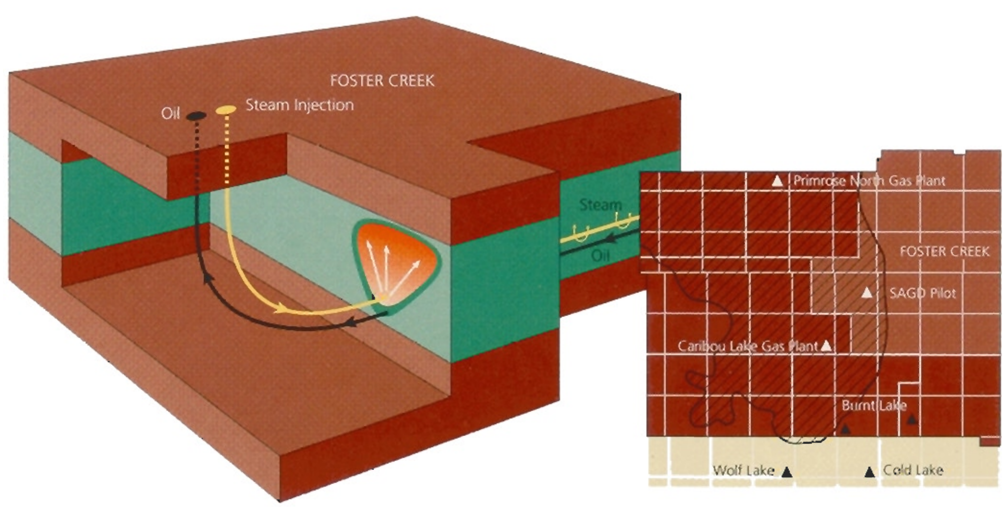
This key production area has potential for shallow, multi zone Cretaceous reservoirs. AEC's proven and probable natural gas reserves in the area total 474 Bcf. Total 1995 production from the area was 103 MMcfd compared with 95 MMcfd in 1994.

The Primrose Range in East Central Alberta is another of AEC's large natural gas properties. AEC controls oil and gas access to this military range and holds exclusive rights to an additional 500,000 net acres on the Alberta portion of the Range which have not been explored. Total production from AEC's Primrose North and Caribou Lake natural gas plants averaged 81 MMcfd during 1995, comparable to the 1994 level. AEC chose not to bring additional reserves onto production while natural gas prices were weak during 1995. Operating costs were exceptionally low at $0.16/Mcf. During 1995, 200 miles of seismic were shot, and 16 wells were drilled with a 94 percent success rate.

The Primrose Range also contains, net to AEC, 21 billion barrels of heavy oil in place. These huge resources are among the highest quality of any undeveloped oil sands and have the potential to substantially increase the Company's future oil production levels. AEC is planning a $13 million pilot project to test Steam Assisted Gravity Drainage (SAGD) technology for recovery of Primrose heavy oil. If the pilot project is successful, the initial commercial production phase of 10,000 B/D could be on-stream in 1997, with the potential to grow to 30,000 B/D by late 1998.

At Frog Lake, a successful 10 well drilling program resulted in 10 oil wells. Production from this area, which averaged 385 B/D, is expected to triple in 1996 with the drilling of 15 additional wells.

Primrose Range – SAGD Pilot Project



This pilot project will consist of two parallel horizontal wells. Steam will be injected into the upper horizontal well while oil and condensed steam will be produced concurrently from the lower well. The project will test the McMurray oil sands formation, which is of the greatest thickness and highest quality in the Foster Creek area of the Range, where AEC owns 100 percent of the oil sands rights.

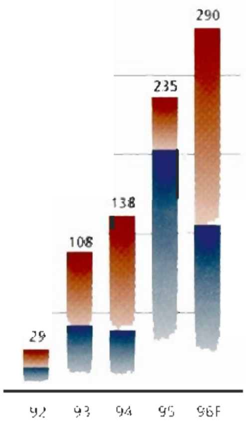
Suffield

This major field in southeast Alberta is AEC's largest oil and gas producing property. Natural gas production was 157 MMcfd during 1995, with operating costs of $0.20/Mcf. During the year, 3 wells were drilled for deeper gas, adding 4 Bcf of proven reserves.

An active drilling program to further exploit Suffield heavy oil resources was conducted during 1995. A total of 78 wells were drilled, resulting in 60 oil wells. Through extensive use of 3-D seismic and horizontal drilling, proven reserves of 6.3 MMBLS were added. In addition, 14.2 MMBLS of probable reserves were added which will be developed with additional drilling and facilities. Production from Suffield increased to 4,998 B/D from 3,806 B/D in 1994, with operating costs of $2.90/bbl. Over half of 1995 production was from the South Jenner field. Major production increases of 990 B/D and 315 B/D were achieved at Area C and Dieppe, respectively.

Increased Drilling

net wells



Reflecting a renewed focus on exploration, AEC expanded its drilling program in 1995.

FUTURE DESTINATIONS – GROWTH OPPORTUNITIES AND STRATEGIES

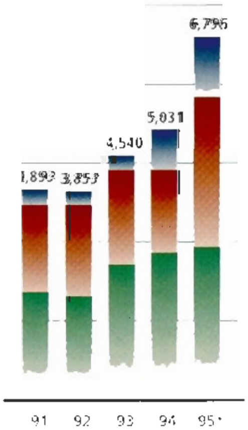
The new AEC will conduct its largest-ever exploration program in 1996. Capital investment for conventional western Canadian oil and gas will be about $400 million. Exploration spending, excluding acquisitions, will reach a record $145 million, as the Company is planning a 25 percent increase in exploration drilling during 1996. Development spending will be $175 million, with 65 percent directed to natural gas and 35 percent directed to oil. Approximately 1,000 sections of exploration land are posted for the first half of 1996. AEC's target for three-year average finding and development costs, on a proven basis, is $0.70/Mcfe or better. Produced gas sales are expected to increase to 530 MMcfd, while western Canadian liquids volumes should grow to 53,500 B/D.

Natural gas development projects in 1996 will include additional drilling and tie-in at the Primrose North and Caribou Lake production facilities in East Central Alberta, as well as at the Boyer property in the Northwest Shallow Gas area. Expected to start up during the second quarter of 1996 are additional compression facilities at Primrose North. In the East Peace River Arch a gathering system and a 45 MMcfd gas plant at Joan (33 percent AEC) also will be operational in the second quarter. At Sexsmith, a 50 MMcfd sweet gas plant (80 percent AEC) is being constructed adjacent to the Sexsmith plant, which will increase total capacity of the complex to 260 MMcfd by the third quarter of 1996. These gas projects are expected to add new reserves and production, with benefits occurring in 1996-97.

Oil development at Suffield during 1996 will include the drilling of 10 horizontal and 26 vertical wells, the horizontal re-entry of another 17 wells and the completion of an oil battery. In the Frog Lake heavy oil area of East Central Alberta, plans include the drilling of 16 directional wells, while the SAGD heavy oil pilot project at Primrose will be pursued.

Growing Reserves

billion cubic feet equivalent (10:1)



AEC's total proven plus probable reserves have increased by about 75 percent over the five-year period.

** Includes Conwest*

Reserves Reconciliation

Western Canada (before royalties)

	Natural Gas (billion cubic feet)			Conventional Oil and Natural Gas Liquids (million barrels)			Syncrude (million barrels)	Argentina (million barrels)
	Proven	Probable	Total	Proven	Probable	Total	Proven	Prov + Prob
1993								
Balance at December 31, 1992	1,461	279	1,740	16.9	8.4	25.3	186	–
Revisions of Established Pools	1	(1)	–	(0.7)	(0.5)	(1.2)	–	–
Discoveries and Extensions	73	12	85	4.9	0.8	5.7	–	–
Acquisition of Reserves - Net	68	31	99	1.0	0.2	1.2	69	–
Production	(121)	–	(121)	(3.3)	–	(3.3)	(9)	–
Balance at December 31, 1993	1,482	321	1,803	18.8	8.9	27.7	246	–
1994								
Revisions of Established Pools	18	(4)	14	3.5	2.5	6.0	33	–
Discoveries and Extensions	75	19	94	8.5	4.1	12.6	–	–
Acquisition of Reserves - Net	73	33	106	(1.0)	(0.7)	(1.7)	–	4.3
Production	(126)	–	(126)	(3.8)	–	(3.8)	(10)	(0.1)
Balance at December 31, 1994	1,522	369	1,891	26.0	14.8	40.8	269	4.2
1995								
Revisions of Established Pools	(7)	(8)	(15)	(0.3)	(0.3)	(0.6)	21	–
Discoveries and Extensions	93	45	138	8.5	15.6	24.1	–	0.1
Acquisition of Reserves - Net	26	1	27	(0.2)	(0.3)	(0.5)	–	0.3
Production	(117)	–	(117)	(4.8)	–	(4.8)	(10)	(0.4)
Balance at December 31, 1995								
AEC	1,517	407	1,924	29.2	29.8	59.0	280	4.2
Conwest	609	333	942	32.3	17.5	49.8	–	–
Combined	**2,126**	**740**	**2,866**	**61.5**	**47.3**	**108.8**	**280**	**4.2**

Landholdings at Year-End 1995

(thousand acres)

	Alberta		Saskatchewan		British Columbia		Western Canada		Argentina	
	Dev	Undev	Dev	Undev	Dev	Undev	Dev	Undev	Dev	Undev
AEC										
Gross	3,159	1,192	44	48	81	266	3,284	1,506	5	452
Net	2,599	1,046	1	26	38	235	2,638	1,307	5	452
Conwest										
Gross	340	854	6	13	22	189	368	1,056	–	–
Net	94	594	1	11	8	125	103	730	–	–
Combined										
Gross	**3,499**	**2,046**	**50**	**61**	**103**	**455**	**3,652**	**2,562**	**5**	**452**
Net	**2,693**	**1,640**	**2**	**37**	**46**	**360**	**2,741**	**2,037**	**5**	**452**

Wells Drilled

(Western Canada)

	1995		1994		1993	
	Gross	Net	Gross	Net	Gross	Net
Exploration						
Gas	19	19	14	12	22	20
Oil	5	5	8	8	13	11
Cased	4	4	7	7	3	3
Dry and Abandoned	18	16	20	18	19	15
Total*	**46**	**44**	**49**	**45**	**57**	**49**
Success Rate (percent)	61	62	59	60	67	69
Operated	45	43	46	44	49	46
Non-Operated	1	1	3	1	8	3
Development						
Gas	110	100	55	50	39	38
Oil	76	66	38	22	31	18
Cased	6	4	9	7	1	1
Dry and Abandoned	27	21	19	14	5	2
Total*	**219**	**191**	**121**	**93**	**76**	**59**
Success Rate (percent)	88	89	85	85	93	97
Operated	200	187	98	89	58	55
Non-Operated	19	4	23	4	18	4
Depth						
Shallow (less than 2,000 feet)	122	117	39	37	19	19
Medium (2,000-9,000 feet)	138	114	124	94	112	87
Deep (more than 9,000 feet)	5	4	7	7	2	2

*Does not include farm-out wells

Syncrude

1995 MILESTONES

Syncrude recorded its sixth consecutive year of record production while continuing to decrease unit operating costs. Major milestones included the following:

- AEC's 13.75 percent share of 1995 production averaged 27,823 B/D, a 6 percent increase over the 1994 level.
- Concurrent with production increases, a decrease in unit operating costs of $1.29/bbl was achieved. The $13.70/bbl unit cost surpassed Syncrude's goal by almost $1.00/bbl. Productivity increased to approximately 15,000 barrels of production per worker compared with 14,000 barrels in 1994. Implementation of new technology and an innovative program in which workers benefit from cost savings was instrumental in lowering operating costs.
- Syncrude acquired an additional oil sands lease which is estimated to contain 3 billion barrels of recoverable bitumen.
- The Province of Alberta introduced a new generic royalty regime for oil sands development, which recognizes the risk taken by oil sands developers. The new regime is expected to be incorporated in Syncrude's royalty system in the near future.

DISCOVER AEC

Working interest of 13.75 percent plus gross overriding royalty

High-quality, light sweet crude oil product

Proven reserve life of 28 years

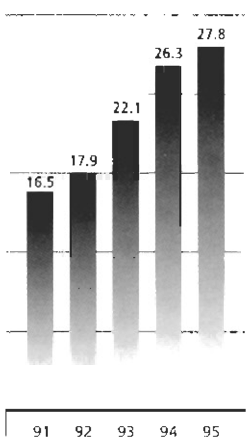
Growing production levels

Decreasing unit costs

FUTURE DESTINATIONS – GROWTH OPPORTUNITIES AND STRATEGIES

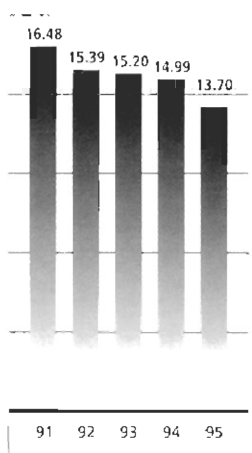
Another year of strong operating performance is expected during 1996. AEC's share of production is estimated to be 27,900 B/D, while unit costs are targeted to decrease by $0.45/bbl to $13.25/bbl.

Growing Syncrude Production
thousand barrels per day



Syncrude has set production records for six consecutive years.

Improving Syncrude Productivity
dollars per barrel - unit cost



Productivity has continued to increase as evidenced by decreasing unit costs concurrent with growing production volumes.

Marketing

1995 MILESTONES

- Canadian natural gas prices fell dramatically during 1995. AEC's produced gas price averaged \$1.40/MMBTU compared with \$1.88/MMBTU during 1994. Approximately 17 percent of AEC's 1995 production was fixed at an average price of \$1.90/Mcf and 46 percent was linked to prices in the eastern U.S., which strengthened late in the year.
- Purchased gas transactions increased from 110 MMcfd to 308 MMcfd in 1995.
- The average price received for AEC's crude oil and NGLs increased from \$20.64/bbl to \$22.47/bbl.
- AEC secured 18 MMcfd of long-term pipeline capacity on the Pacific Gas Transmission system and 40 MMcfd on the proposed Northern Border and Natural Gas Pipeline expansions. AEC has an additional 82 MMcfd of direct firm transportation to U.S. markets. In total, AEC has access to 470 MMcfd of ex-Alberta transportation which represents 85 percent of its 1996 field capability of 550 MMcfd.
- A new pipeline equalization formula was negotiated for Suffield heavy oil production, which increased the price on 5,000 B/D by \$2.05/bbl.
- AEC moved the point of sale on 5,000 B/D of light, sweet conventional crude downstream from the field to Edmonton, resulting in a price increase of \$0.17/bbl on that production.
- A new program for oil swaps resulted in approximately 50 percent of anticipated pre-merger 1996 oil production being hedged at a price of \$23.51/bbl.

DISCOVER AEC

Industry leadership in new marketing services

Optimizing oil and gas assets through marketing, storage and trading

Growing direct market access through transportation capacity

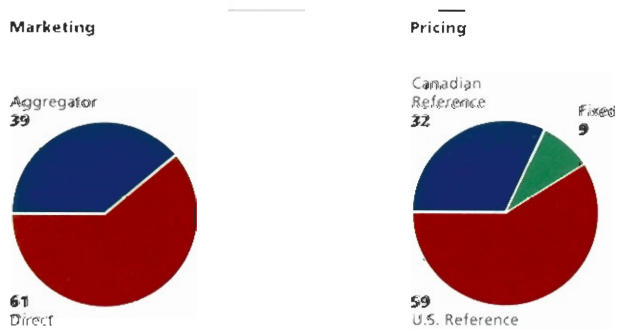
FUTURE DESTINATIONS – GROWTH OPPORTUNITIES AND STRATEGIES

AEC is in a position to react quickly to increase production when natural gas markets improve. The natural gas storage facility will continue to provide considerable flexibility in managing AEC's natural gas production. AEC's combined field production and storage withdrawals could average well over 590 MMcfd in 1996 should gas prices warrant this level. In addition, if gas development projects were reactivated, AEC could quickly bring field capability up by 50 MMcfd.

AEC has joined the Northern Area Transportation Study (NATS) which will evaluate the feasibility of a new gas pipeline that would provide additional direct access to U.S. markets for western Canadian natural gas.

1996 Produced Gas Sales

percent



AEC continues to increase the amount of produced gas it markets directly. Almost 60 percent of AEC gas sales are based on higher U.S. reference prices.

Argentina

1995 MILESTONES

During the past year, AEC invested $16 million to acquire properties and pursue exploration and development opportunities in the high-potential, largely undeveloped Néuquen Basin of Argentina.

➢ A 100 percent interest in the 79,400-acre Anticlinal Campamento property was purchased, which added 250,000 barrels to AEC's reserves. This brings AEC's total Argentine oil and gas rights under lease to 456,780 acres. A 23-square-mile, high-resolution 3-D seismic program was shot over the field in preparation for an enhanced recovery pilot test during 1996.

➢ Seismic programs were conducted on the Covunco, Puesto Prado, and Estancia Vieja properties. The high-quality data positions AEC to select drilling locations for 1996.

➢ A successful development well was drilled on the Estancia Vieja property.

➢ Total Argentine production averaged 1,090 B/D compared with 260 B/D during 1994, reflecting a full year of production in 1995.

DISCOVER AEC

Control of large, contiguous blocks of exploration lands

Excellent lease tenure and tax and royalty regimes

Growing reserves and production

Producing properties with enhanced recovery potential

FUTURE DESTINATIONS – GROWTH OPPORTUNITIES AND STRATEGIES

Argentina is characterized by geological formations similar to those of the Western Canadian Sedimentary Basin. Due to lack of capital, however, Argentine exploration and production lags behind North America by 20 to 30 years. This provides many exploration opportunities for use of 3-D seismic and other technology such as horizontal drilling that have been very successful in western Canada.

Up to 10 percent of AEC's total 1996 exploration and production capital will be invested in Argentina. Specific goals include the doubling of oil production to 2,500 B/D by year-end. Six development and three exploration wells are planned, with a goal of increasing proven and probable reserves by 4 million barrels on a boe basis. Initiatives will be taken to decrease drilling costs by 25 percent and to reduce operating costs to less than $5/bbl. Acquisitions and farm-ins that involve long-term leases and beneficial royalty and tax arrangements will be pursued.

Supplemental INFORMATION – EXPLORATION AND PRODUCTION

(Unaudited)

CONSOLIDATED STATEMENT OF EARNINGS

($ millions) Year ended December 31	*Gas and NGLs* 1995	1994	1993	*Conventional Oil* 1995	1994	1993	*Syncrude* 1995	1994	1993	*Marketing* 1995	1994	1993
Revenue	**$172.9**	$ 247.6	$ 231.2	**$ 86.6**	$ 61.2	$ 46.2	**$246.7**	$ 214.1	$ 174.6	**$129.8**	$ 83.5	$ 47.8
Royalties	**17.9**	33.4	30.7	**14.7**	8.9	5.9	**30.7**	9.8	5.1	**–**	–	–
Net Revenue	**155.0**	214.2	200.5	**71.9**	52.3	40.3	**216.0**	204.3	169.5	**129.8**	83.5	47.8
Operating costs	**32.1**	34.5	29.4	**14.7**	13.2	11.9	**139.1**	142.2	126.9	**3.9**	2.0	1.6
Cost of gas purchased	**–**	–	–	**–**	–	–	**–**	–	–	**126.9**	83.0	35.4
Operating G&A	**17.5**	21.9	18.2	**5.3**	5.5	5.0	**–**	–	–	**2.3**	1.9	1.9
Operating Cash Flow	**105.4**	157.8	152.9	**51.9**	33.6	23.4	**76.9**	62.1	42.6	**(3.3)**	(3.4)	8.9
Depreciation, depletion and amortization	**92.6**	95.4	88.3	**19.2**	14.7	12.0	**17.3**	15.9	14.0	**–**	–	–
Operating Income	**12.8**	62.4	64.6	**32.7**	18.9	11.4	**59.6**	46.2	28.6	**(3.3)**	(3.4)	8.9
Equity earnings	**–**	–	3.2	**–**	–	–	**–**	–	–	**–**	–	–
Divisional Income	**$ 12.8**	$ 62.4	$ 67.8	**$ 32.7**	$ 18.9	$ 11.4	**$ 59.6**	$ 46.2	$ 28.6	**$ (3.3)**	$ (3.4)	$ 8.9

($ millions)	*International* 1995	1994	1993	*Other* 1995	1994	1993	*Total* 1995	1994	1993
Revenue	**$ 7.6**	$ 1.7	$ –	**$ –**	$ 14.7	$ –	**$643.6**	$622.8	$499.8
Royalties	**0.2**	–	–	**–**	–	–	**63.5**	52.1	41.7
Net Revenue	**7.4**	1.7	–	**–**	14.7	–	**580.1**	570.7	458.1
Operating costs	**4.4**	0.7	–	**–**	–	–	**194.2**	192.6	169.8
Cost of gas purchased	**–**	–	–	**–**	–	–	**126.9**	83.0	35.4
Operating G&A	**3.7**	1.2	–	**–**	–	–	**28.8**	30.5	25.1
Operating Cash Flow	**(0.7)**	(0.2)	–	**–**	14.7	–	**230.2**	264.6	227.8
Depreciation, depletion and amortization	**2.5**	0.7	–	**–**	–	–	**131.6**	126.7	114.3
Operating Income	**(3.2)**	(0.9)	–	**–**	14.7	–	**98.6**	137.9	113.5
Equity earnings	**–**	–	–	**–**	–	–	**–**	–	3.2
Divisional Income	**$ (3.2)**	$ (0.9)	$ –	**$ –**	$ 14.7	$ –	**98.6**	137.9	116.7
Corporate G&A							**14.6**	16.3	12.8
Corporate DD&A							**2.3**	5.8	1.8
Interest and foreign exchange							**9.7**	35.1	4.7
Income taxes							**34.4**	32.2	36.6
Net Earnings – Exploration and Production							**$ 37.6**	$ 48.5	$ 60.8
Earnings per Common Share									
Basic							**$ 0.50**	$ 0.65	$ 0.82
Fully diluted							**$ 0.48**	$ 0.64	$ 0.81

Supplemental INFORMATION – EXPLORATION AND PRODUCTION

(Unaudited)

CONSOLIDATED BALANCE SHEET

($ millions) As at December 31	1995	1994
Assets		
Current assets	$ **194.2**	$ 154.3
Capital assets	**1,594.7**	1,489.1
Investments and other assets	**7.2**	13.7
	$ **1,796.1**	$ 1,657.1
Liabilities		
Current liabilities	$ **179.5**	$ 155.3
Long-term debt	**153.5**	232.8
Other liabilities	**45.4**	43.3
Deferred income taxes	**390.4**	358.6
	768.8	790.0
Capital employed	**1,027.3**	867.1
	$ **1,796.1**	$ 1,657.1

Note: Includes allocation of corporate assets and liabilities

CONSOLIDATED STATEMENT OF OPERATING, INVESTING AND FINANCING ACTIVITIES

($ millions) Year ended December 31	1995	1994	1993
Operating Activities			
Net earnings	$ **37.6**	$ 48.5	$ 60.8
Depreciation, depletion and amortization	**133.9**	132.5	116.1
Deferred income taxes	**21.0**	5.0	5.2
Other	**3.3**	17.1	5.5
Cash Flow from Operations – Exploration and Production	$ **195.8**	$ 203.1	$ 187.6
Investing Activities			
Capital investment	$ **(239.9)**	$ (283.5)	$ (183.7)
Proceeds on disposal of assets and investments	**4.3**	73.9	60.9
	$ **(235.6)**	$ (209.6)	$ (122.8)
Financing Activity			
Net repayment of long-term debt	$ **(79.3)**	$ (11.7)	$ (59.7)

Note: Includes corporate allocations

Supplemental INFORMATION – EXPLORATION AND PRODUCTION

(Unaudited)

OPERATING STATISTICS	Year 1995	Q4 1995	Q3 1995	Q2 1995	Q1 1995	1994	1993	1992	1991
SALES									
Produced Gas (million cubic feet per day)	**320**	367	241	305	367	345	332	300	273
Oil and Natural Gas Liquids (barrels per day)									
Western Canada									
Syncrude	**27,823**	29,180	29,554	29,177	23,297	26,282	22,118	17,870	16,510
Conventional	**11,549**	14,021	11,002	10,808	10,331	9,267	7,939	6,886	5,419
Natural gas liquids	**1,691**	1,839	1,806	1,733	1,379	1,011	984	1,003	1,051
Total Canada	**41,063**	45,040	42,362	41,718	35,007	36,560	31,041	25,759	22,980
Argentina	**1,090**	1,019	1,050	1,157	1,135	260	–	–	–
Total	**42,153**	46,059	43,412	42,875	36,142	36,820	31,041	25,759	22,980
PER-UNIT RESULTS (Western Canada)									
Produced Gas ($ per thousand cubic feet)									
Price	**1.40**	1.50	1.19	1.25	1.65	1.88	1.75	1.37	1.35
Royalties	**0.13**	0.11	0.12	0.14	0.16	0.25	0.24	0.15	0.14
Operating costs	**0.27**	0.27	0.25	0.33	0.26	0.27	0.24	0.25	0.23
Net back	**1.00**	1.12	0.82	0.78	1.23	1.36	1.27	0.97	0.98
Conventional Oil ($ per barrel)									
Price	**20.54**	19.47	19.60	22.58	20.89	18.09	15.93	16.88	15.73
Royalties	**3.48**	3.13	3.33	4.27	3.32	2.63	2.01	2.53	2.73
Operating costs	**3.47**	4.11	3.26	3.63	2.64	3.87	4.06	3.60	5.20
Net back	**13.59**	12.23	13.01	14.68	14.93	11.59	9.86	10.75	7.80
Natural Gas Liquids ($ per barrel)									
Price	**15.74**	16.64	14.63	16.27	15.31	15.05	15.71	14.79	14.52
Royalties	**5.25**	6.54	5.21	4.78	4.17	3.98	4.04	4.12	3.94
Net back	**10.49**	10.10	9.42	11.49	11.14	11.07	11.67	10.67	10.58
Syncrude ($ per barrel)									
Price, net of tariff	**23.69**	22.57	23.08	25.05	24.19	21.76	20.97	22.79	22.67
Gross overriding royalty	**0.60**	0.13	0.64	0.88	0.81	0.56	0.86	1.37	1.44
Sulphur and other revenue	–	–	–	–	–	–	(0.19)	(0.04)	0.17
Royalties	**3.02**	3.75	3.06	3.22	1.81	1.03	0.64	–	–
Cash operating costs	**13.70**	12.65	11.89	11.88	19.68	14.99	15.20	15.39	16.48
Net back	**7.57**	6.30	8.77	10.83	3.51	6.30	5.80	8.73	7.80

	Forecast 1996	1995	1994	1993	1992	1991
GAS PRODUCTION BY AREA (million cubic feet per day)						
Suffield	**140**	**157**	169	178	189	200
West Peace River Arch	**290**	**80**	68	56	46	38
East Central Alberta	**100**	**103**	95	58	40	37
Northwest Shallow Gas	**20**	**16**	9	5	3	3
Total field capability	**550**	**356**	341	297	278	278
Storage (injection) withdrawal	**(20)**	**(36)**	(7)	14	22	(5)
Native gas from storage	–	–	11	21	–	–
Total produced gas sales	**530**	**320**	345	332	300	273
PRODUCED GAS SALES BY CONTRACT (million cubic feet per day)						
TransCanada Gas Services	**100**	**111**	146	168	178	158
Pan-Alberta Gas	**45**	**31**	38	38	44	37
ProGas	**55**	**22**	11	6	7	6
Long-term direct	**105**	**90**	72	49	19	19
Other	**225**	**66**	78	71	52	53
Total	**530**	**320**	345	332	300	273
PURCHASED GAS TRANSACTIONS (million cubic feet per day)	**330**	**308**	110	51	77	46
OIL AND NGL PRODUCTION BY AREA (barrels per day)						
Western Canada						
Syncrude	**27,900**	**27,823**	26,282	22,118	17,870	16,510
Suffield	**5,600**	**4,998**	3,806	4,186	4,036	3,062
East Peace River Arch	**5,800**	**5,361**	3,917	2,362	1,700	1,591
West Peace River Arch	**12,900**	**2,466**	1,800	1,701	1,827	1,591
East Central Alberta	**1,300**	**392**	477	372	–	–
Other	–	**23**	278	302	326	226
Subtotal	**53,500**	**41,063**	36,560	31,041	25,759	22,980
Argentina	**2,500**	**1,090**	260	–	–	–
Total	**56,000**	**42,153**	36,820	31,041	25,759	22,980

Supplemental INFORMATION – EXPLORATION AND PRODUCTION

(Unaudited)

OPERATING STATISTICS	1995	1994	1993	1992	1991
UNDEVELOPED ACREAGE (thousand acres)					
Western Canada					
AEC – Gross	**1,506**	1,220	1,254	1,485	1,827
– Net	**1,307**	976	967	1,071	1,272
Conwest – Gross	**1,056**	995	960	970	958
– Net	**730**	637	540	550	568
Combined Total					
Gross	**2,562**	2,215	2,214	2,455	2,785
Net	**2,037**	1,613	1,507	1,621	1,840
Argentina					
Gross	**452**	376	282	–	–
Net	**452**	376	282	–	–

RESERVES (before royalties)	1995	1994	1993	1992	1991
Gas (billion cubic feet)					
AEC – Proven	**1,517**	1,522	1,482	1,461	1,485
– Probable	**407**	369	321	279	254
AEC Total	**1,924**	1,891	1,803	1,740	1,739
Conwest Total – Proven & Probable	**942**	704	519	415	284
Combined Total	**2,866**	2,595	2,322	2,155	2,023
Conventional Oil and Natural Gas Liquids (million barrels)					
AEC – Proven	**29.2**	26.0	18.8	16.9	14.2
– Probable	**29.8**	14.8	8.9	8.4	8.2
AEC Total	**59.0**	40.8	27.7	25.3	22.4
Conwest Total – Proven & Probable	**49.8**	47.6	36.2	34.5	28.0
Combined Total	**108.8**	88.4	63.9	59.8	50.4
Syncrude (million barrels)	**280**	269	246	186	193
Argentina Oil (million barrels)	**4.2**	4.2	–	–	–

FINDING AND DEVELOPMENT COST CALCULATION (Western Canada)	1995	1994	1993	1992	1991
Conventional Oil and Gas Investment ($ millions)					
Exploration (gross)	**82.7**	66.1	53.8	22.9	45.5
Development	**97.3**	101.7	56.8	25.1	41.5
Maintenance	**2.7**	3.3	12.1	8.7	8.4
Acquisitions	**9.4**	66.3	17.6	11.1	3.2
Total finding and development costs	**192.1**	237.4	140.3	67.8	98.6
Less incentives	**–**	–	–	–	(0.8)
Net conventional oil and gas capital investment	**192.1**	237.4	140.3	67.8	97.8
Proven Reserves Added					
Gas (billion cubic feet)					
Discoveries and extensions	**93.1**	75.1	73.1	23.0	63.9
Revisions	**(6.5)**	17.5	1.0	35.0	113.7
Acquisitions	**30.3**	95.1	67.9	39.1	9.5
Total	**116.9**	187.7	142.0	97.1	187.1
Conventional Oil and Natural Gas Liquids (million barrels)					
Discoveries and extensions	**8.5**	8.5	4.9	2.3	1.0
Revisions	**(0.3)**	3.5	(0.7)	2.2	(4.6)
Acquisitions	**–**	0.1	1.0	1.1	0.1
Total	**8.2**	12.1	5.2	5.6	(3.5)
Total Reserve Additions 10:1 (billion cubic feet of gas equivalent)	**198.9**	308.7	194.0	153.1	152.1
Finding and Development Costs					
($ per thousand cubic feet equivalent) – 10:1	**0.97**	0.77	0.72	0.44	0.65
– 6:1	**1.16**	0.91	0.81	0.52	0.59

Reaching NEW MARKETS

TRANSPORTATION, STORAGE AND PROCESSING

AEC's pipelines, natural gas storage and gas processing investments add value to its Exploration and Production business. These investments provide a stable source of cash flow as well as many opportunities for growth.

Pipelines

1995 MILESTONES

Northeast Alberta

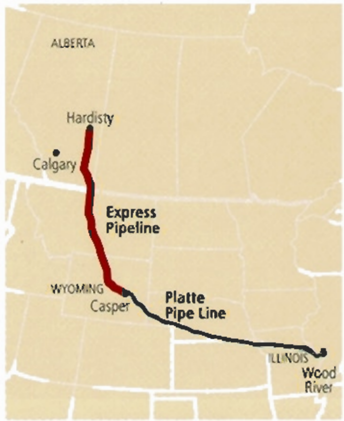
Oil production from this area continued to grow during 1995, as reflected by the record throughput on both of the Company's wholly owned pipelines in the region.

- Throughput on the Alberta Oil Sands Pipeline (AOSPL) system averaged 202,400 B/D during 1995. AEC responded to the growing levels of Syncrude production by initiating the first phase of an AOSPL expansion which will increase capacity to 230,000 B/D from 215,000 B/D by March 1996. As well, a major proactive program to ensure pipeline integrity and reliability continued during the year.
- Heavy oil volumes transported via the Cold Lake Oil Pipeline (CLPL) system averaged 141,500 B/D. An expansion of the CLPL system, from its existing capacity of 215,000 B/D to a peak capacity of 258,000 B/D, is expected to be completed by early 1997.

Express Pipeline

While the production capabilities of Canadian crude oil producers are increasing, U.S. oil production is declining. The proposed Express Pipeline will provide new markets for western Canadian oil in the U.S. Rocky Mountain states and Illinois.

Express Pipeline Project



This project, in which AEC is a 50 percent participant, is unique among oil pipelines because of its long-term, contractual arrangements for assured pipeline capacity. By mid-December 1995, following an Open Season process, commitments from shippers, including AEC, totaled about 85 percent (145,000 B/D) of available Express Pipeline capacity. The majority of commitments were for a 15-year contract period.

The Cdn $530 million pipeline will run 785 miles from Hardisty, Alberta to Casper, Wyoming. At Casper it will connect with the Platte Pipe Line, which the Express Pipeline partners have contracted to purchase in the first quarter of 1996. Through Platte a portion of the oil shipped via Express will be delivered from Casper to a refining centre at Wood River, Illinois. The system will batch transport several types of crude oil, ranging from lighter synthetic oil to heavier bitumen blends.

A joint National Energy Board/Canadian Environmental Assessment Agency hearing regarding the Canadian portion of the pipeline began in January 1996. A public review of the U.S. portion of the project also is under way.

Assuming receipt of regulatory approvals during the second quarter, construction of the Express Pipeline could be completed by late 1996.

DISCOVER AEC

Entrepreneurial, non-utility investments

Stable source of cash flow and earnings

Largest intra-Alberta oil pipeline operator

Vancouver Island Natural Gas Pipeline

At year-end AEC sold its 50 percent interest in Pacific Coast Energy Corporation, which owns the natural gas pipeline to Vancouver Island.

FUTURE DESTINATIONS – GROWTH OPPORTUNITIES AND STRATEGIES

AEC will continue to seek opportunities to increase its pipelines investments through acquisition or expansion of existing pipelines or the construction of new pipelines. AEC is participating in the National Task Force on Oil Sands Development and, as the major oil pipeliner in northeast Alberta, is well positioned to expand service to producers in this region. The second phase of the AOSPL expansion, to a capacity of 240,000 B/D, will be completed by year-end 1996. Expansion of the CLPL system will meet the anticipated 1997 needs of Cold Lake area producers.

Pipeline Rate Base Summary

Unaudited (\$ millions)	*AEC Interest*	*Rate Base* 1995	1994	1993	1992	1991	*Divisional Income* 1995	1994	1993	1992	1991
Alberta Oil Sands Pipeline	100%	**70**	71	69	57	63	**5.4**	6.6	4.6	9.0	10.4
Cold Lake Pipeline	100%	**206**	206	205	205	203	**35.3**	36.3	33.7	36.9	36.7
						Other	**(0.6)**	4.7	4.8	4.3	5.7
						Total	**40.1**	47.6	43.1	50.2	52.8

Pipeline Throughput

(all liquids pipelines) (million barrels)	1995	1994	1993	1992	1991
	196	189	183	175	171

Natural Gas Storage

1995 MILESTONES

- Capacity of the Company's AECO C HUB™ storage facility at Suffield was increased to 1.8 Bcfd of design injection/withdrawal capacity and 88 Bcf of storage capacity.
- A major initiative in establishing AEC's integral position in North American natural gas hub services and trading was the implementation of an innovative HUB-To-HUB™ service between AEC and Union Gas of Ontario. The service provides producers, aggregators, marketers, utilities and industrial users with "synthetic" firm transportation between two major Canadian trading and transaction points – the AECO C storage facility in southeastern Alberta and the Union hub at the Dawn storage facility south of Sarnia, Ontario.
- AECO-LINK™, the electronic connection between AECO C and its customers, was integrated with the NrG Highway system, a North American pipeline nomination network. Customers can now communicate with the AECO-LINK™ system through NrG.

DISCOVER AEC

Dominant Canadian gas storage and market centre

Growing North American position in gas hub services and trading

Low-cost operator

Hub-to-hub services

State-of-the-art electronic information systems

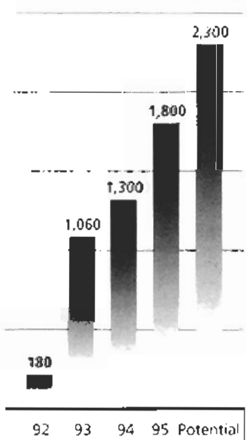
FUTURE DESTINATIONS – GROWTH OPPORTUNITIES AND STRATEGIES

The outlook is for increased financial contributions from gas storage during 1996 because the 1995 expansion will be operational for the full year and gas markets are expected to tighten during 1996.

The Company will continue to pursue gas storage and trading opportunities in North America that leverage AEC's leadership role in hub and hub-to-hub services. AEC is prepared to expand capacity of the AECO C storage facility to meet market demand for storage and other third-party services.

Building Suffield Gas Storage Capacity

million cubic feet per day injection/withdrawal capacity



AEC continues to expand its storage facility to meet the growing demand for storage and other marketing services.

Natural Gas Processing

AEC has a 45 percent joint venture interest in a new liquids extraction plant under construction at Empress, Alberta. The plant will have the capacity to process 1.0 Bcfd of natural gas, with initial emphasis on recovery of propane and heavier hydrocarbons. Start-up of the plant, in which AEC's investment is $35 million, is expected in the third quarter of 1996.

AEC also owns one-half of Pan-Alberta Resources Inc. (PARI), which holds a 50 percent interest in the Empress II natural gas liquids extraction plant. This facility operates on a cost-of-service basis and receives a share of net profits from the sale of liquids.

Supplemental INFORMATION – TRANSPORTATION, STORAGE AND PROCESSING

(Unaudited)

CONSOLIDATED STATEMENT OF EARNINGS

($ millions) Year ended December 31	Pipelines 1995	1994	1993	Gas Storage 1995	1994	1993	Natural Gas Processing and Investment 1995	1994	1993	Total 1995	1994	1993
Revenue	**$ 81.4**	$ 81.3	$ 82.3	**$ 18.9**	$ 23.5	$ 7.2	**$ 49.4**	$ 61.9	$ 52.1	**$ 149.7**	$ 166.7	$ 141.6
Operating costs	**21.6**	19.0	18.0	**3.8**	3.9	0.8	**35.8**	52.3	41.9	**61.2**	75.2	60.7
Operating G&A	**6.2**	4.1	9.0	**4.3**	0.7	0.3	–	–	–	**10.5**	4.8	9.3
Operating Cash Flow	**53.6**	58.2	55.3	**10.8**	18.9	6.1	**13.6**	9.6	10.2	**78.0**	86.7	71.6
Depreciation, depletion and amortization	**13.2**	13.5	15.0	**6.1**	4.1	0.9	**1.8**	1.7	1.7	**21.1**	19.3	17.6
Operating Income	**40.4**	44.7	40.3	**4.7**	14.8	5.2	**11.8**	7.9	8.5	**56.9**	67.4	54.0
Equity earnings	**(0.3)**	2.9	2.8	**–**	–	–	**3.5**	3.1	4.2	**3.2**	6.0	7.0
Divisional Income	**$ 40.1**	$ 47.6	$ 43.1	**$ 4.7**	$ 14.8	$ 5.2	**$ 15.3**	$ 11.0	$ 12.7	**60.1**	73.4	61.0
Corporate G&A										**5.2**	2.3	4.8
Corporate DD&A										**0.8**	0.4	0.6
Interest and foreign exchange										**20.1**	13.6	8.1
Income taxes										**15.3**	23.4	19.1
Net Earnings - Transportation, Storage and Processing										**$ 18.7**	$ 33.7	$ 28.4
Earnings per Common Share												
Basic										**$ 0.25**	$ 0.46	$ 0.38
Fully diluted										**$ 0.24**	$ 0.45	$ 0.37

CONSOLIDATED BALANCE SHEET

($ millions) As at December 31	1995	1994
Assets		
Current assets	**$ 31.9**	$ 29.3
Capital assets	**343.0**	333.4
Investments and other assets	**47.5**	67.0
	$ 422.4	$ 429.7
Liabilities		
Current liabilities	**$ 23.7**	$ 29.8
Long-term debt	**230.9**	229.6
Other liabilities	**1.6**	1.3
Deferred income taxes	**33.5**	41.4
	289.7	302.1
Capital employed	**132.7**	127.6
	$ 422.4	$ 429.7

Note: Includes allocation of corporate assets and liabilities

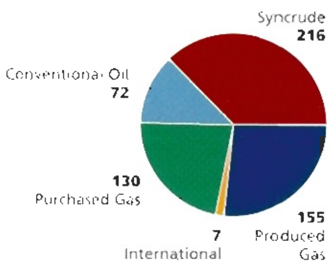
CONSOLIDATED STATEMENT OF OPERATING, INVESTING AND FINANCING ACTIVITIES

($ millions) Year ended December 31	1995	1994	1993
Operating Activities			
Net earnings	**$ 18.7**	$ 33.7	$ 28.4
Depreciation, depletion and amortization	**21.9**	19.7	18.2
Deferred income taxes	**3.2**	2.0	(0.1)
Other	**6.6**	1.6	1.9
Cash Flow from Operations – Transportation, Storage and Processing	**$ 50.4**	$ 57.0	$ 48.4
Investing Activities			
Capital investment	**$ (31.1)**	$ (56.3)	$ (68.3)
Proceeds on disposal of assets and investments	**15.1**	0.7	0.3
	$ (16.0)	$ (55.6)	$ (68.0)
Financing Activity			
Net issue of long-term debt	**$ 1.3**	$ 26.0	$ 26.7

Note: Includes corporate allocations

1995 Exploration and Production Net Revenue by Segment

millions of dollars



The Management Discussion and Analysis on pages 26 through to 32 is to be read in conjunction with the Audited Consolidated Financial Statements.

AEC's results are reported in two segments which include an appropriate allocation of Corporate costs. Exploration and Production is comprised of the Company's domestic and international oil and natural gas exploration, production and marketing operations. Transportation, Storage and Processing includes the pipeline, natural gas storage and gas processing operations and a Syncrude electrical utility investment.

1995 was a year of significant change for AEC. The process of rationalizing the Company's businesses to focus on Oil and Gas culminated with the sale of its Forest Products Division on August 25, 1995. Results from Forest Products operations up to the point of sale and the gain on disposal have been shown as Discontinued Operations and are described in Note 4 of the Consolidated Financial Statements.

AEC's strong balance sheet has allowed it to adopt a counter-cyclical growth strategy to make significant investments during a time of industry retrenchment. In January 1996, the Company acquired Conwest Exploration Company Limited, an oil and gas exploration and production company, as described in Note 15 of the Consolidated Financial Statements.

RESULTS OF OPERATIONS

Exploration and Production

1995 COMPARED WITH 1994

Revenues, net of royalties, increased 2 percent to $580.1 million. The accompanying table shows the details of this change by product.

Oil and Natural Gas Revenue Change

($ millions)	*Price*	*Volume*	*Royalties and Other*	*Total*
Natural gas	(59.5)	(17.4)	17.7	(59.2)
Oil – Conventional	10.3	15.1	(5.8)	19.6
– Syncrude	19.7	12.2	(20.2)	11.7
– International	0.5	5.4	(0.2)	5.7
Purchased gas sales	(104.0)	150.3	–	46.3
Other*	–	–	(14.7)	(14.7)
Total	(133.0)	165.6	(23.2)	9.4

* *Gain on sale of investments*

Natural gas prices declined to $1.40/MMBTU from $1.88/MMBTU in the prior year, which reflected the continuing surplus of natural gas in western Canada that results from downstream transportation restrictions. Prices strengthened in the fourth quarter to average $1.50/MMBTU as a result of the winter heating season demand. The average price includes the impact of arbitration settlements concluded in 1994 and 1995. Approximately 60 percent of the volumes available for sale in 1995 were linked to U.S. prices. A gas price swap program was established in 1995 and at December 31, 1995, 14.2 MMcfd was contracted at an average price of $1.62 per Mcf for various periods, all of which end in 1996.

Natural gas production volumes sold were 320 MMcfd, down from 345 MMcfd in 1994, as the Company elected to inventory volumes in anticipation of higher prices. Production volumes increased from 341 MMcfd in 1994 to 356 MMcfd in 1995. The excess of production over sales was injected into storage. At year-end 1995, produced gas inventory in storage was 15 Bcf, up from 2 Bcf in 1994.

Oil prices improved for both conventional and Syncrude operations. Conventional oil prices rose 14 percent to \$20.54/bbl (1994 – \$18.09/bbl). Syncrude prices improved from \$21.76/bbl to \$23.69/bbl in 1995, an improvement of 9 percent. Prices, net of royalties, for Argentinean oil averaged \$18.28/bbl, up 5 percent from the 1994 average of \$17.42/bbl. These increases parallel a year-over-year increase in the West Texas Intermediate (WTI) average to U.S. \$18.40/bbl from U.S. \$17.19/bbl, with only a small variation in exchange rates. At December 31, 1995, the Company had 22,000 B/D of 1996 sales subject to fixed price agreements averaging \$23.51/bbl.

At February 5, 1996 the unrealized settlement asset related to the Company's oil and natural gas price swaps was \$1.3 million compared to an unrealized settlement liability of \$11.0 million at December 31, 1995.

Canadian conventional oil and natural gas liquid volumes rose to 13,240 B/D, an increase of 29 percent from 1994, primarily as a result of exploration and development activity in the East Peace River Arch and Suffield areas. Syncrude's volumes increased 6 percent to a record 27,823 B/D reflecting higher facility throughputs. International volumes increased to 1,090 B/D (1994 – 260 B/D) as a result of the first full year of production from the Estancia Vieja property, acquired in the fourth quarter of 1994, and the acquisition of the Anticlinal Campamento property in 1995.

Product Unit Net Back *(\$ per Unit)*	*Natural Gas (Mcf)*		*Conventional Oil (bbl)*		*Syncrude (bbl)*	
	1995	*1994*	*1995*	*1994*	*1995*	*1994*
Revenue	**1.40**	1.88	**20.54**	18.09	**23.69**	21.76
Gross overriding royalty	**–**	–	**–**	–	**0.60**	0.56
Royalties	**0.13**	0.25	**3.48**	2.63	**3.02**	1.03
Operating costs	**0.27**	0.27	**3.47**	3.87	**13.70**	14.99
Net back	**1.00**	1.36	**13.59**	11.59	**7.57**	6.30

Natural gas unit net backs declined 26 percent due to lower prices. Conventional oil net backs increased by 17 percent as a result of higher prices and lower costs which were partially offset by an increase in royalties. Oil operating costs per unit declined due to improved operating efficiency and higher production volumes. Syncrude oil net backs increased 20 percent for the same reasons as conventional oil net backs. While royalty rates generally track changes in prices, the increasing profitability of the Company's oil sands investment attracted a significantly higher royalty. Improved productivity and operating cost efficiency helped to cushion the impact.

Purchased gas sales rose to 308 MMcfd from a 1994 total of 110 MMcfd as a result of increased trading activity to capture profits from price volatility in the short-term market. At December 31, 1995, the Company had contracts in place to purchase 63 Bcf of gas over a three-year period. Contracts also were in place to deliver 66 Bcf. They will be supplied from gas to be acquired and gas held in inventory. At year-end, purchased gas held in inventory amounted to 3 Bcf.

1994 COMPARED WITH 1993

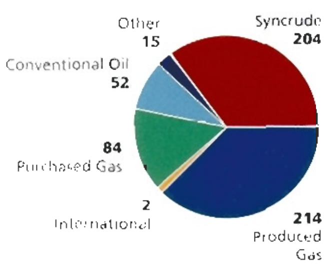
Exploration and Production revenues, net of royalties, for 1994 increased by $112.6 million to $570.7 million. The accompanying table shows this increase on a product basis.

Oil and Natural Gas Revenue Change

($ millions)	Price	Volume	Royalties and Other	Total
Natural gas	19.6	8.3	(14.2)	13.7
Oil – Conventional	7.3	7.7	(3.0)	12.0
– Syncrude	7.6	31.9	(4.7)	34.8
– International	–	1.7	-	1.7
Purchased gas sales	(19.6)	55.3	-	35.7
Other*	–		14.7	14.7
Total	14.9	104.9	(7.2)	112.6

* Gain on sale of investments

1994 Exploration and Production Net Revenue by Segment
millions of dollars



Natural gas prices increased to $1.88/MMBtu from $1.76/MMBtu as markets improved in the first part of 1994. Natural gas prices declined over the second and third quarters of 1994 as a surplus of natural gas developed in western Canada. Natural gas prices improved towards the end of the year as the winter heating season commenced. Natural gas revenue in 1993 included arbitration and decontracting settlements.

Syncrude oil prices averaged $21.76/bbl (1993 – $20.97/bbl) and prices for conventional oil averaged $18.09/bbl (1993 – $15.93/bbl). The lower Canadian dollar led to improved oil prices despite the lower WTI crude oil average of U.S. $17.19/bbl in 1994 (1993 – $18.48/bbl). Volume increases for natural gas and conventional oil reflected new production arising from exploration and development activity. The Syncrude volume increase resulted from the inclusion of a full year of production from the additional 3.75 percent interest in Syncrude which AEC acquired on July 1, 1993. Purchased gas sales were higher as marketing trading activities increased.

Product Unit Net Back

($ per Unit)	Natural Gas (Mcf) 1994	Natural Gas (Mcf) 1993	Conventional Oil (bbl) 1994	Conventional Oil (bbl) 1993	Syncrude (bbl) 1994	Syncrude (bbl) 1993
Revenue	1.88	1.75	18.09	15.93	21.76	20.97
Gross overriding royalty	–	–	-		0.56	0.86
Sulphur and other revenue	–	–	–	–	–	(0.19)
Royalties	0.25	0.24	2.63	2.01	1.03	0.64
Operating costs	0.27	0.24	3.87	4.06	14.99	15.20
Net back	1.36	1.27	11.59	9.86	6.30	5.80

Natural gas unit net backs increased 7 percent as a result of higher prices. Conventional oil unit net backs increased 18 percent due to higher prices and lower operating costs, partially offset by higher royalties. Oil operating costs per unit declined due to improved operating efficiency and higher volumes produced. Syncrude oil unit net backs increased 9 percent for the same reasons as conventional oil net backs.

The majority of produced natural gas was sold under short and long-term contracts. Approximately 60 percent of 1994 produced gas sales were tied to U.S. prices. At December 31, 1994, contracts were in place to resell 34 Bcf of purchased natural gas during 1995 and 1996. The gas to complete the sales was comprised of 24 Bcf purchased under contracts in place and 10 Bcf withdrawn from gas storage.

Transportation, Storage and Processing

1995 COMPARED WITH 1994

Revenue declined to $149.7 million from $166.7 million in 1994 due primarily to lower revenues from the natural gas processing plant. Lower costs of the natural gas feed stock more than offset this decline and natural gas processing plant operating income increased 49 percent to $11.8 million.

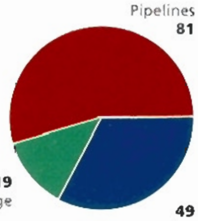
Pipeline operating income decreased 10 percent to $40.4 million in 1995 partially as a result of project investigation costs.

Gas storage revenues decreased to $18.9 million from $23.5 million in 1994. Increases in general and administrative costs and higher depreciation, depletion and amortization expense reduced operating income to $4.7 million from $14.8 million in 1994. Costs increased as a result of project development costs and the impact of a full year of the expanded storage facility operation.

In December 1995, the Company sold its 50 percent investment in Pacific Coast Energy Corporation, owner of the Vancouver Island natural gas pipeline.

1995 Transportation, Storage and Processing Revenue by Segment

millions of dollars



1994 COMPARED WITH 1993

Revenue increased to $166.7 million in 1994 from $141.6 million in 1993. Contributing to this increase was higher revenue from natural gas storage in 1994 as AEC expanded its storage capacity and customer base. The increase reflects storage revenue of $23.5 million in 1994, compared with $7.2 million in 1993. Revenue from natural gas processing was higher due to increased throughput. Operating costs over the two-year period also were higher, reflecting the increased activity.

CONSOLIDATED SUMMARY

1995 COMPARED WITH 1994

Net earnings increased to $110.2 million in 1995, 10 percent higher than 1994. This improvement was due to the gain on the sale of the Forest Products Division of $37.4 million, higher oil prices and volumes, the 1994 impact of foreign exchange expense not incurred in 1995 and lower Syncrude operating costs. Significantly lower natural gas prices, increased royalties on Syncrude production and the 1994 sale of investments partially offset these gains.

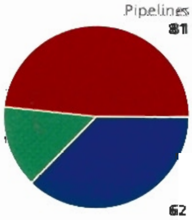
On a Continuing Operations basis, excluding Forest Products, net earnings fell $25.9 million to $56.3 million from $82.2 million in 1994. The decline in natural gas operating income, as a consequence of lower prices, was the major factor in the change. Increases in interest costs due to higher average cost of debt (1995 – 8.5 percent, 1994 – 7.8 percent) were more than offset by decreases in foreign exchange costs and lower average long-term debt levels.

Consolidated cash flow from operations was $270.7 million, down from $294.8 million. Cash flow from Continuing Operations fell to $246.2 million from $260.1 million in 1994.

Cash income tax, excluding income tax payable on the gain on sale of the Forest Products Division, amounted to $39.2 million in 1995 (1994 – $59.1 million).

1994 Transportation, Storage and Processing Revenue by Segment

millions of dollars



On a consolidated basis net revenues decreased to $729.8 million (1994 – $737.4 million). Increased oil and purchased gas revenues offset decreases in natural gas and natural gas processing revenues. Operating expenses decreased to $294.7 million from $303.1 million primarily due to lower natural gas processing operating costs. Cost of gas purchased increased primarily as a result of higher volumes of natural gas purchased for resale, partially offset by a lower unit cost per Mcf.

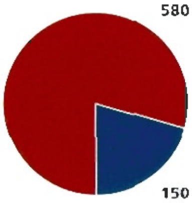
General and administrative expense increased to $19.8 from $18.6 million in 1994, due to the inclusion of $2.0 million of one-time costs related to streamlining the Company's operations.

Foreign exchange expense fell $32.1 million to $1.7 million from $33.8 million in 1994 while interest expense increased $13.2 million to $28.1 million (1994 – $14.9 million). The termination of a U.S. dollar denominated currency swap increased Canadian debt levels and concurrently eliminated this foreign exchange exposure.

1995 Consolidated Net Revenue by Division

millions of dollars

Exploration and Production
580



150
Transportation, Storage and Processing

Depreciation, depletion and amortization increased to $155.8 million (1994 – $152.2 million) due to an increase in the per unit rate and higher oil sales volumes, partially offset by lower gas volumes.

Equity earnings were down $2.8 million in 1995 primarily due to a loss on disposition of Pacific Coast Energy Corporation.

1994 COMPARED WITH 1993

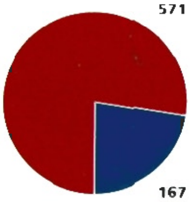
Net earnings of $100.5 million in 1994 were 10 percent higher than in 1993. This improvement was due to gains on the sale of investments and higher prices (partially as a result of the lower Canadian dollar) for natural gas, pulp, and lumber which more than offset higher foreign exchange and interest expense and lower lumber volumes. Cash flow from operations was up 17 percent to $294.8 million. This figure reflects the payment of cash income taxes in the amount of $59.1 million (1993 – $51.2 million).

For Continuing Operations, revenues were up $137.7 million to $737.4 million. Operating expenses increased to $303.1 million from $264.9 million. The changes in revenue and operating costs primarily reflect increases from Syncrude and natural gas. In addition, revenue included $14.7 million from the gain on the sale of Pan-Alberta Gas Ltd. and Chieftain International, Inc. The cost of gas purchased of $83.0 million (1993 – $35.4 million) reflects increased marketing activity related to sales of purchased gas.

1994 Consolidated Net Revenue by Division

millions of dollars

Exploration and Production
571



167
Transportation, Storage and Processing

General and administrative expenses of $18.6 million included $1.7 million in office consolidation expenses. Interest expense, which increased from $8.1 million to $14.9 million, reflects a higher AEC average cost of debt (1994 – 7.8 percent; 1993 – 6.2 percent), increased debt levels (1994 – $561.8 million, 1993 – $528.2 million) and lower interest income. Foreign exchange expense increased substantially to $33.8 million from the 1993 amount of $4.7 million. The 1994 amount includes $22.3 million from the repatriation of $118.3 million of U.S. dollar debt. The balance of the increase results from the erosion of the U.S./Canadian exchange rate during 1994. Depreciation, depletion and amortization totaled $152.2 million, compared with $134.3 million, the increase related to higher sales volumes for natural gas and oil. Equity earnings for 1994 were $6.0 million, down $4.2 million from 1993, reflecting the sale of Pan-Alberta Gas Ltd. in 1994. Income taxes of $55.6 million (1993 – $55.7 million) reflected the higher level of operating income in 1994 offset by higher interest and foreign exchange costs and an increase in non-deductible Crown royalties.

LIQUIDITY AND CAPITAL RESOURCES

Capital investment of $302.1 million was $67.3 million lower than 1994. Western Canadian conventional Exploration and Production capital totaled $183.6 million, up from $171.1 million in 1994, excluding acquisitions. The Company's 1995 capital program was directed primarily to drilling and completions in its focus areas in Alberta. Acquisitions in 1995 were $9.4 million compared to $66.3 million in 1994. Syncrude capital requirements increased to $28.1 million due to the acquisition of an oil sands lease and equipment modernization. International capital decreased from $22.6 million to $16.1 million.

Capital investment in Transportation, Storage and Processing was $30.5 million and included $15.5 million in additions to the gas storage facility and $12.3 million for the Company's share of a new ethane extraction plant at Empress.

Year-end debt levels fell to $384.4 million from $561.8 million reflecting the application of $304.9 million proceeds from the Forest Products disposition. The 1995 capital program was funded through cash flow from operations and cash received on the sale of investments. In 1995, the Company increased the number of its revolving credit and term loan facilities to four by adding a new facility for $125 million, with a syndicate of banks. The total available under all facilities is $500 million with an average term of 8 years and is wholly unsecured. At December 31, 1995, the Company had $123.1 million of these facilities utilized. On June 30, 1996, $100 million of unsecured debentures mature. The repayment will be made using long-term debt.

RISK MANAGEMENT

The Company's results are influenced by factors such as product prices, interest and foreign exchange rates, royalties, taxes and operations.

Risk exposure is managed through a combination of insurance, commodity price swap agreements, its system of internal controls and sound operating practices. In periods of currency volatility the Company may also use currency swaps to hedge against foreign exchange fluctuations. At year-end, there were no currency swaps in place.

In addition to limits established by the Board of Directors on the use of commodity price swap agreements, a rigorous system of internal control procedures has been established. Credit risks are managed by transacting only with preauthorized financial counterparties where agreements are in place. Credit limits are established and are closely monitored.

An active program of monitoring and reporting day-to-day operations ensures environmental and regulatory standards are met. Contingency plans are in place to ensure timely response to an event.

AEC is exposed to risks and uncertainties inherent in foreign operations, including regulatory and legislative changes. None of these operations are expected to have a material adverse effect on the Company.

OUTLOOK

In January 1996, the Company acquired the shares of Conwest Exploration Company Limited (Conwest). The acquisition was financed through the issuance of Common Shares in the amount of $539 million, cash of $351.9 million and the assumption of $237.6 million of long-term debt. The cash portion was financed by an additional new long-term debt facility in the amount of $375 million with a syndicate of banks. Outlook information discussed below includes the addition of Conwest operations.

Sales in 1996 are expected to grow to 530 MMcfd of natural gas (1995 - 320 MMcfd) and 56,000 B/D of oil and liquids (1995 - 42,153 B/D) as a result of the merger with Conwest and prior years' capital programs. Prices are expected to remain near current levels with some potential upside driven by contracts indexed to U.S. gas prices. Fluctuations will be mitigated by the Company's price swap programs. In 1996, a change in natural gas prices of $0.10/Mcf would change cash flow from operations by approximately $16 million. A U.S. $1.00 per barrel change in oil price would change cash flow from operations by approximately $19 million. Approximately 59 percent of gas contracts will be tied to U.S. reference prices. Of total sales, 39 percent will be to aggregators. Capital investment for Exploration and Production is expected to rise to over $400 million. Interest and exchange rates are expected to remain largely unchanged from 1995 levels.

Transportation, Storage and Processing operations are expected to provide a stable source of earnings and cash flow. Capital expenditures for ongoing operations are expected to be $56 million. The proposed Express oil pipeline from Alberta into the Midwest United States is currently proceeding through the regulatory approval process. As a part of this project, the Company and its partner announced on January 15, 1996 they had entered into an agreement to acquire the Platte Pipe Line system (Platte). Platte extends the proposed Express line from Casper, Wyoming, to refinery markets at Wood River, Illinois.

The Company will continue to assess the way in which it finances its operations to achieve the desired growth in a financially prudent way. It is the Company's intention that Exploration and Production debt-to-cash flow be about 2.0x after the acquisition of Conwest and carrying out the large 1996 capital program.

The Company intends to finance its capital program through cash flow from operations, long-term debt and the disposition of non-core assets.

February 5, 1996

Management Report

The accompanying consolidated financial statements and all information in this annual report are the responsibility of Management. The financial statements have been prepared by Management in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best judgements. Financial information contained throughout this annual report is consistent with these financial statements.

Management has developed and maintains an extensive system of internal control that provides reasonable assurance that all transactions are accurately recorded, that the financial statements realistically report the Company's operating and financial results and that the Company's assets are safeguarded. The Company's Internal Audit department reviews and evaluates the adequacy of and compliance with the Company's internal controls. As well, it is the policy of the Company to maintain the highest standard of ethics in all its activities.

AEC's Board of Directors has approved the information contained in the financial statements. The Board fulfills its responsibility regarding the financial statements mainly through its Audit Committee.

Price Waterhouse, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to examine the consolidated financial statements and provide an independent professional opinion.

Gwyn Morgan
President and
Chief Executive Officer

J.D. Watson
Vice-President, Finance
and Chief Financial Officer

Auditors' Report

To the Shareholders of Alberta Energy Company Ltd.:

We have audited the consolidated balance sheets of Alberta Energy Company Ltd. as at December 31, 1995 and December 31, 1994 and the consolidated statements of earnings, retained earnings and changes in financial position for each of the years in the three-year period ended December 31, 1995. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1995 and December 31, 1994 and the results of its operations and the changes in its financial position for each of the years in the three-year period ended December 31, 1995, in accordance with generally accepted accounting principles.

Price Waterhouse

Chartered Accountants

Calgary, Alberta
February 5, 1996

CONSOLIDATED STATEMENT OF EARNINGS

($ millions, except per share amounts) Year Ended December 31	Note Reference	1995	1994	1993
Revenues, Net of Royalties		**$ 729.8**	$ 737.4	$ 599.7
Costs and Expenses				
Operating		**294.7**	303.1	264.9
Cost of gas purchased		**126.9**	83.0	35.4
General and administrative		**19.8**	18.6	17.6
Interest, net	2	**28.1**	14.9	8.1
Foreign exchange		**1.7**	33.8	4.7
Depreciation, depletion and amortization		**155.8**	152.2	134.3
Earnings Before the Undernoted		**102.8**	131.8	134.7
Equity earnings		**3.2**	6.0	10.2
Income taxes	3	**(49.7)**	(55.6)	(55.7)
Net Earnings from Continuing Operations		**56.3**	82.2	89.2
Net Earnings from Discontinued Operations	4	**53.9**	18.3	2.4
Net Earnings		**$ 110.2**	$ 100.5	$ 91.6
Earnings from Continuing Operations per Common Share				
Basic		**$ 0.75**	$ 1.11	$ 1.20
Fully diluted		**$ 0.72**	$ 1.09	$ 1.18
Earnings per Common Share				
Basic		**$ 1.47**	$ 1.36	$ 1.23
Fully diluted		**$ 1.44**	$ 1.34	$ 1.21

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

($ millions) Year Ended December 31	1995	1994	1993
Balance, Beginning of Year	**$ 384.3**	$ 314.9	$ 253.4
Net Earnings	**110.2**	100.5	91.6
	494.5	415.4	345.0
Dividends - Preferred shares	–	3.0	5.8
- Common shares	**29.8**	28.1	24.3
	29.8	31.1	30.1
Balance, End of Year	**$ 464.7**	$ 384.3	$ 314.9

See accompanying notes to the consolidated financial statements.

CONSOLIDATED BALANCE SHEET

($ millions) *As at December 31*	*Note Reference*	*1995*	*1994*
ASSETS			
Current Assets			
Cash and short-term investments, at cost which approximates market		**$ 64.2**	$ 23.7
Accounts receivable and accrued revenue		**132.8**	154.0
Inventories	*5*	**29.1**	67.5
		226.1	245.2
Capital Assets	*6*	**1,937.7**	2,017.7
Investments and Other Assets	*7*	**54.7**	94.7
		$ 2,218.5	$ 2,357.6
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Bank indebtedness	*8*	**$ –**	$ 23.2
Accounts payable and accrued liabilities		**175.2**	201.9
Income taxes payable		**26.5**	4.4
Current portion of long-term debt		**1.5**	11.0
		203.2	240.5
Long-Term Debt	*9*	**384.4**	561.8
Other Liabilities	*10*	**47.0**	44.6
Deferred Income Taxes		**423.9**	448.8
		1,058.5	1,295.7
Shareholders' Equity			
Share capital	*11*	**692.3**	673.3
Retained earnings		**464.7**	384.3
Foreign currency translation adjustment		**3.0**	4.3
		1,160.0	1,061.9
		$ 2,218.5	$ 2,357.6

See accompanying notes to the consolidated financial statements.

Approved by the Board:

Director

Director

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

($ millions, except per share amounts) Year Ended December 31	1995	1994	1993
Operating Activities			
Net earnings from Continuing Operations	$ 56.3	$ 82.2	$ 89.2
Depreciation, depletion and amortization	155.8	152.2	134.3
Deferred income taxes	24.2	7.0	5.1
Other	9.9	18.7	7.4
Cash Flow from Continuing Operations	246.2	260.1	236.0
Cash Flow from Discontinued Operations	24.5	34.7	15.4
Cash Flow from Operations	270.7	294.8	251.4
Net change in non-cash working capital-Continuing Operations	17.8	(48.1)	60.1
Net change in non-cash working capital-Discontinued Operations	37.1	(9.3)	(0.5)
	325.6	237.4	311.0
Investing Activities			
Capital investment-Continuing Operations	(271.0)	(339.8)	(252.0)
Proceeds on disposal of Forest Products	218.0	–	–
Proceeds on disposal of assets and investments	19.4	74.6	61.2
Investing activities of Discontinued Operations	(30.9)	(28.9)	(8.4)
Investments and other	(2.4)	(1.5)	6.0
	(66.9)	(295.6)	(193.2)
Dividends			
Preferred share dividends	–	(3.0)	(5.8)
Common share dividends	(29.8)	(28.1)	(24.3)
	(29.8)	(31.1)	(30.1)
Increase (Decrease) in Cash before Financing Activities	228.9	(89.3)	87.7
Financing Activities			
Issue of long-term debt	25.0	208.0	111.9
Repayment of long-term debt-Continuing Operations	(103.0)	(193.7)	(144.9)
Preferred share conversion and redemption	–	(75.0)	–
Financing activities of Discontinued Operations	(106.2)	7.0	–
Issue of common shares	19.0	85.8	10.7
	(165.2)	32.1	(22.3)
Increase (decrease) in cash and short-term investments less bank indebtedness	$ 63.7	$ (57.2)	$ 65.4
Cash and short-term investments less bank indebtedness, end of year	$ 64.2	$ 0.5	$ 57.7
Cash Flow from Continuing Operations per Common Share			
Basic	$ 3.28	$ 3.59	$ 3.30
Fully diluted	$ 3.18	$ 3.40	$ 3.11
Cash Flow from Operations per Common Share			
Basic	$ 3.61	$ 4.07	$ 3.52
Fully diluted	$ 3.51	$ 3.88	$ 3.33

See accompanying notes to the consolidated financial statements.

1995 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in $ millions, unless otherwise indicated)

1. Summary of Significant Policies

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Alberta Energy Company Ltd. (the "Company") and its subsidiaries, all of which are wholly owned.

Investments in jointly controlled companies, jointly controlled partnerships and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships over which the Company has significant influence are accounted for using the equity method.

A listing of major subsidiaries, affiliates, unincorporated joint ventures and partnerships is on page 52.

(B) CAPITAL ASSETS

Exploration and Production

Conventional The Company accounts for conventional oil and gas properties in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry.

All costs associated with the acquisition, exploration and development of oil and gas reserves are capitalized in cost centres on a country by country basis. Direct general and administrative costs related to exploration activities are capitalized.

Depletion and depreciation are calculated using the unit-of-production method based on estimated proven reserves, before royalties. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. All capitalized costs are subject to depletion and depreciation including costs related to unproven properties as well as estimated future costs to be incurred in developing proven reserves.

Future removal and site restoration costs are estimated and recorded over approximately 20 years.

A ceiling test is applied to ensure that capitalized costs do not exceed the sum of estimated undiscounted, unescalated future net revenues from proven reserves less the cost incurred or estimated to develop those reserves, related production, interest and general and administration costs, and an estimate for restoration costs and applicable taxes. The calculations are based on sales prices and costs at the end of the year. The Company has never taken a write-down of capital assets as a result of the ceiling test.

Oil sands Capital assets associated with surface mineable projects are accumulated, at cost, in separate cost centres. Substantially all of these costs are amortized using the unit-of-production method based on estimated proven developed reserves applicable to each project.

Transportation, Storage and Processing

Capital assets related to pipelines are carried at cost and depreciated using the straight-line method over the remaining term of each applicable pipeline service agreement.

Capital assets related to NGL extraction plant operations are carried at cost and depreciated using the straight-line method over the initial term of the cost-of-service contracts.

Capital assets related to gas storage facilities are recorded at cost and depreciated on the straight-line basis over 20 years.

(C) FOREIGN CURRENCY TRANSLATION

Operations outside Canada are considered to be self-sustaining and use their primary currency for recording substantially all transactions. The accounts of self-sustaining foreign subsidiaries are translated using the current rate method, whereby assets and liabilities are translated at year-end exchange rates while revenues and expenses are converted using average annual rates. Translation gains and losses relating to these subsidiaries are deferred and included in shareholders' equity.

Long-term debt payable in U.S. dollars is translated into Canadian dollars at the year-end exchange rate, with any resulting adjustment amortized using the straight-line method over the remaining life of the debt.

(D) PROJECT INVESTIGATION COSTS

Project investigation costs for new business opportunities are charged to earnings as incurred until such time as the commercial viability of the project is established. Subsequent expenditures are capitalized and amortized on a basis appropriate for the project.

(E) INVENTORIES

Inventories are valued at the lower of cost or estimated net realizable value.

(F) INTEREST CAPITALIZATION

Interest is capitalized during the construction phase of large capital projects.

(G) HEDGING ACTIVITIES

Settlement of crude oil and natural gas price swap agreements, which have been arranged as a hedge against commodity price and currency fluctuations, are reflected in product revenues at the time of sale of the related hedged production.

(H) COMPARATIVE FIGURES

Certain 1994 and 1993 figures have been reclassified for comparative purposes.

2. Interest, Net

	1995	*1994*	*1993*
Interest expense – long-term debt	**$ 46.0**	$ 34.8	$ 26.5
Interest expense – other	**–**	1.5	1.4
Interest income	**(4.2)**	(2.7)	(4.4)
	41.8	33.6	23.5
Less interest allocated to Discontinued Operations *(Note 4)*	**13.7**	18.7	15.4
Total	**$ 28.1**	$ 14.9	$ 8.1

3. Income Taxes

The provision for income taxes has been allocated as follows:

	1995	1994	1993
Continuing Operations	$ 49.7	$ 55.6	$ 55.7
Discontinued Operations (Note 4)	13.7	14.5	2.3
Total income taxes	$ 63.4	$ 70.1	$ 58.0

	1995	1994	1993
Current	$ 36.8	$ 57.1	$ 49.4
Deferred	24.2	11.0	6.8
Alberta royalty tax credit	(1.5)	(1.9)	(1.8)
Large corporations tax	3.9	3.9	3.6
Income taxes	$ 63.4	$ 70.1	$ 58.0

The following table reconciles income taxes calculated at statutory rates with actual income taxes:

	1995	1994	1993
Earnings before income taxes and gain on sale			
Continuing Operations	$ 106.0	$ 137.8	$ 144.9
Discontinued Operations	30.2	32.8	4.7
Total	$ 136.2	$ 170.6	$ 149.6
Income taxes at statutory rate of 44.6% (1994 – 44.3%)	$ 60.7	$ 75.6	$ 66.3
Effect on taxes resulting from:			
Non-deductibility of crown payments and depreciation, depletion and amortization	21.1	25.5	21.9
Federal resource allowance	(21.5)	(25.0)	(23.0)
Utilization of tax losses	(1.4)	(6.4)	(4.2)
Alberta royalty tax credit	(1.5)	(1.9)	(1.8)
Large corporations tax	3.9	3.9	3.6
Other	2.1	(1.6)	(4.8)
Income taxes (Effective rate: 1995 – 46.5%, 1994 – 41.1%)	$ 63.4	$ 70.1	$ 58.0

The Company's U.S. subsidiaries have approximately U.S. $12.0 million of tax losses available which can be applied, with certain restrictions, against future taxable income earned in the U.S. The benefit of these tax losses, which will expire between 1999 and 2010, has not been recorded. The amount of capital assets without a tax base is $147.0 million (1994 – $162.4 million).

4. Discontinued Operations

On August 25, 1995 the Company sold its Forest Products Division which consisted of its interest in the Slave Lake Pulp Partnership and its Blue Ridge Lumber Division. Net cash proceeds of $304.9 million ($218.0 million net of working capital, income taxes and expenses) were used to retire debt. The Company's operations, cash flow and gain on sale relating to the Forest Products Division have been reflected in the consolidated financial statements and notes on a Discontinued Operations basis.

The results of Discontinued Operations for the comparative periods are summarized as follows:

	1995	1994	1993
Revenue	$ 135.2	$ 184.0	$ 137.3
Operating costs	83.9	120.8	105.5
Depreciation, depletion and amortization	6.7	9.5	9.8
Operating income	44.6	53.7	22.0
Interest and foreign exchange	14.4	20.9	17.3
Income taxes	13.7	14.5	2.3
Net earnings from operations	16.5	18.3	2.4
Gain on sale (net of income tax recovery of $7.3 million)*	37.4	–	–
Net earnings from Discontinued Operations	$ 53.9	$ 18.3	$ 2.4

* *Income tax recovery includes utilization of capital losses.*

The Consolidated Balance Sheet includes the following amounts applicable to the Forest Products operations:

	1994
Current assets	$ 61.6
Capital assets	195.2
Other assets	14.0
Total assets	$ 270.8
Current liabilities	$ 55.4
Long-term debt	99.4
Deferred income taxes	48.8
Capital employed	67.2
Total liabilities and equity	$ 270.8

5. Inventories

	1995	1994
Parts and supplies	$ 14.0	$ 22.5
Raw materials	–	13.8
Finished goods	0.6	10.8
Gas in storage	14.5	20.4
	$ 29.1	$ 67.5

6. Capital Assets

	1995			1994		
Property, Plant and Equipment	*Cost*	*Accumulated DD&A**	*Net*	*Cost*	*Accumulated DD&A**	*Net*
Exploration and production	**$ 2,648.9**	**$ 1,054.2**	**$ 1,594.7**	$ 2,502.6	$ 1,013.5	$ 1,489.1
Transportation, storage and processing	**566.4**	**223.4**	**343.0**	536.1	202.7	333.4
Forest products	**–**	**–**	**–**	273.6	78.4	195.2
	$ 3,215.3	**$ 1,277.6**	**$ 1,937.7**	$ 3,312.3	$ 1,294.6	$ 2,017.7

* *Depreciation, depletion and amortization*

General and administrative expenses capitalized to oil and gas properties during the year amounted to $10.5 million (1994 – $6.6 million).

The prices used in the ceiling test evaluation of the Company's Canadian conventional reserves at December 31, 1995 were as follows:

Natural gas: $ 1.77 per million Btu

Oil and natural gas liquids: $ 19.99 per barrel

7. Investments and Other Assets

	1995	*1994*
Investments	**$ 45.4**	$ 63.2
Unrealized foreign exchange loss, net of amortization	**–**	20.0
Deferred pension assets	**7.9**	10.0
Other	**1.4**	1.5
	$ 54.7	$ 94.7

8. Bank Indebtedness

In 1994 the Slave Lake Pulp Partnership, a 75 percent proportionately consolidated affiliate, had a working capital credit facility in the amount of $37.5 million (75 percent) which was secured by a general assignment of accounts receivable and inventories. This facility was cancelled in conjunction with the disposition of the Forest Products Division (Note 4).

9. Long-Term Debt

	Note Reference	1995	1994
ALBERTA ENERGY COMPANY LTD.			
Canadian dollar debt			
Revolving credit and term loan borrowings	*B*		
Term loans		$ –	$ 15.0
Notes payable		**123.1**	206.8
Unsecured debentures	*C*		
10.50%, due June 1996		**100.0**	–
8.15%, due July 2003		**100.0**	100.0
9.50%, due February 2000		**25.0**	25.0
9.85%, due March 2002		**25.0**	–
U.S. dollar debt			
U.S. Swap Agreement, due June 1996	*D*	–	122.8
		373.1	469.6
NON-RECOURSE LONG-TERM DEBT*			
Canadian dollar debt			
Term loans	*E*	**12.8**	14.3
U.S. dollar debt			
Project financing - notes payable	*F*	–	88.9
		12.8	103.2
Total long-term debt		**385.9**	572.8
Current portion of long-term debt		**1.5**	11.0
		$ 384.4	$ 561.8

* *Amounts stated are AEC's proportionate share of debt of other entities.*

(A) MANDATORY FIVE-YEAR DEBT REPAYMENTS

The minimum annual repayments of long-term debt required over each of the next five years are as follows:

1996	1997	1998	1999	2000
$ 101.5	$ 1.5	$ 1.5	$ 1.5	$ 26.5

(B) REVOLVING CREDIT AND TERM LOAN BORROWINGS

In 1995, the Company increased the number of its revolving credit and term loan facilities to four by adding a new facility for $125 million with a syndicate of banks. The four facilities, totalling $500 million, are fully revolving for 364-day periods with provision for extensions at the option of the lenders and upon notice from the Company. If not extended, one facility converts to a non-revolving reducing loan for a term of 6.5 years, a second one for a term of 7 years and the others for terms of 8 years.

All four loan facilities are unsecured and available in Canadian and/or U.S. dollar equivalent amounts; they currently bear interest either at the lenders' rates for Canadian prime commercial or U.S. base rate loans, or at Bankers' Acceptance rates, or at LIBOR plus applicable margins.

Alenco Inc., a subsidiary of the Company, has a U.S. $20 million unsecured revolving credit and term loan facility, none of which was utilized at year-end. This facility is guaranteed by the Company and is fully revolving until 1997 with provision for yearly extensions at the option of the lender following notice from Alenco Inc. If not extended, the facility converts to a revolving reducing facility to be repayable in full by the end of seven years.

Notes payable consist of Bankers' Acceptances and Commercial Paper maturing at various dates with a weighted average interest rate of 6.25% (1994 – 5.96%). Notes payable shown as long-term debt represent amounts which are not expected to require the use of working capital during the year and are fully supported by the availability of term loans under the revolving credit facilities.

(C) UNSECURED DEBENTURES

The unsecured 10.50% debentures mature June 30, 1996. The repayment of this issue at maturity will be made using other long-term debt. In February 1995, under its Medium Term Note Program, the Company issued $25 million in unsecured debentures bearing interest at 9.85% payable semi-annually and maturing on March 15, 2002.

(D) U.S. SWAP AGREEMENT

Effective January 6, 1995, the Company terminated a U.S. dollar swap agreement which effectively had converted the 10.50% Canadian $100 million unsecured debentures into U.S. dollar debt of $87.6 million bearing interest at a rate set semi-annually.

(E) TERM LOANS

AEC has a 49.995 percent interest in Pan-Alberta Resources Inc. ("PARI") which has a non-recourse secured term credit facility which finances its investment in its natural gas liquids extraction plant joint venture. The term credit facility is secured by PARI's interest in the joint venture assets and certain related agreements. The debt is repayable over the initial term of the related joint venture contracts in equal monthly installments totaling $1.5 million (49.995 percent) per year.

Canadian dollar loans bear interest at the lenders' rates for Canadian prime commercial loans or at Bankers' Acceptance rates plus applicable margins.

At year-end, outstanding obligations under the facility included Bankers' Acceptances (Canadian) and Canadian dollar loans of $12.8 million (49.995 percent) ($14.3 million in 1994).

(F) PROJECT FINANCING

On August 25, 1995, the project financing of Slave Lake Pulp Partnership ("SLPP"), comprised of bank loans arranged with a syndicate of banks in the principal amount of U.S. $58.1 million (75 percent), was repaid from the proceeds received on the disposition of the Forest Products Division (Note 4). AEC had a 75 percent interest in SLPP.

10. Other Liabilities

	1995	1994
Future removal and site restoration costs	**$ 26.1**	$ 21.5
Long-term liabilities related to Syncrude	**11.8**	13.8
Deferred acquisition payable	**5.0**	5.0
Other	**4.1**	4.3
	$ 47.0	$ 44.6

11. Share Capital

Authorized

20,000,000	First Preferred Shares
20,000,000	Second Preferred Shares
20,000,000	Third Preferred Shares
Unlimited	Common Shares
5,000,000	Non-Voting Shares

	1995		1994	
	Number of Shares	Amount	Number of Shares	Amount
ISSUED AND OUTSTANDING				
Second Preferred Shares, Series 2				
7.75% Deferred Convertible Redeemable				
with a paid up amount of $25 per share	–	$ –	2,999,700	$ 75.0
Preferred shares redeemed for cash	–	–	(161,793)	(4.1)
Preferred shares converted				
to common shares	–	–	(2,837,907)	(70.9)
	–	$ –	–	$ –
Common Shares				
Balance, beginning of year	**74,464,114**	**$ 673.3**	69,993,447	$ 587.5
Issued on conversion of				
preferred shares	–	–	3,632,437	70.9
Shareholder Investment Plan	**750,694**	**14.3**	662,842	12.5
Employee Savings Plan	–	–	23,111	0.5
Employee Share Option Plan	**324,211**	**4.7**	152,277	1.9
Balance, end of year	**75,539,019**	**$ 692.3**	74,464,114	$ 673.3

The Employee Share Option Plan provides for granting to employees of the Company and its subsidiaries options to purchase Common Shares of the Company. Each option granted under the plan expires after seven years and may be exercised in cumulative annual amounts of 25 percent on or after each of the first four anniversary dates of the grant.

At December 31, 1995, employee share options, exerciseable between 1996 and 2002 were outstanding to purchase 3,093,002 (1994 – 2,469,079) Common Shares at prices ranging from $12.04 to $21.88 per share.

	1995	*1994*
Common Shares under option, beginning of year	**2,469,079**	2,265,356
Share options granted	**1,151,200**	557,000
Share options exercised	**(324,211)**	(152,277)
Share options cancelled	**(203,066)**	(201,000)
Common Shares under option, end of year	**3,093,002**	2,469,079

The number of Common Shares reserved for issuance under the Employee Share Option Plan was 3,115,743 at December 31, 1995 (3,289,954 at December 31, 1994).

12. Financial Instruments and Hedging Activities

(A) FINANCIAL ASSETS AND LIABILITIES

The Company's financial instruments are included in the Consolidated Balance Sheet and are comprised of cash and short-term investments, accounts receivable, and all current liabilities and long-term borrowings. The fair values of financial instruments other than long-term borrowings approximate their carrying amount due to the short-term maturity of these instruments.

The estimated fair values of long-term borrowings have been determined based on the Company's assessment of available market information and appropriate valuation methodologies.

	1995		*1994*	
	Balance Sheet Amount	*Fair Value*	*Balance Sheet Amount*	*Fair Value*
Long-term debt	**$ 384.4**	**$ 396.5**	$ 561.8	$ 552.5

Derivatives are used only to reduce specific risk exposures and are not held for trading purposes.

(B) CREDIT RISK

A substantial portion of the Company's sales are with customers with whom long-term relationships have been established. All natural gas and crude oil price swap agreements are with major financial institutions. The risk of significant credit loss is considered remote.

(C) INTEREST RISK

At December 31, 1995, the increase or decrease in annual interest costs on floating rate debt amounts to $1.2 million for each one percent change in interest rates.

(D) HEDGING

The Company's Board has authorized crude oil and natural gas price swaps as a hedge for up to 75 million cubic feet per day of produced gas sales, to an aggregate maximum of $100 million, 75 million cubic feet per day of purchased gas sales, to an aggregate maximum of $75 million for terms not exceeding 3 years, and the lesser of 25,000 barrels per day of crude oil or 50 percent of the Company's annual budgeted production, for terms not exceeding 18 months.

At December 31, 1995, 22,000 barrels per day of oil for 1996 and 14.2 million cubic feet per day of gas for various periods up to one year, are subject to price swap arrangements at an average of $23.51 per barrel and $1.62 per thousand cubic feet respectively. Based on prices at December 31, 1995, the unrealized settlement liability on these contracts amounts to $11.0 million. The amount recognized by the Company will be dependent on prices in effect at time of settlement.

13. Supplementary Information

(A) INVESTMENTS PROPORTIONATELY CONSOLIDATED

The Company conducts a substantial portion of its conventional oil and gas activity through unincorporated joint ventures which are accounted for using the proportionate consolidation method. In addition, the following investments also are accounted for using the proportionate consolidation method:

Percent Interest	*1995*	*1994*	*1993*
Pan-Alberta Resources Inc.	**49.995**	49.995	49.995
Syncrude Joint Venture (including 75% of AEC Oil Sands Limited Partnership)	**13.75**	13.75	13.75
Ethane Gathering System Joint Venture	**33.3**	33.3	33.3

The Company has included in its accounts the following aggregate amounts in respect of the above-listed jointly controlled companies, unincorporated joint ventnres and jointly controlled partnerships:

	1995	*1994*	*1993*
Continuing Operations			
Assets	**$ 397.9**	$ 380.2	$ 375.0
Liabilities	**104.0**	98.6	80.6
Revenues, net of royalties	**269.8**	269.9	225.8
Operating expenses	**177.1**	196.0	170.4
Operating income	**72.6**	55.2	38.6
Operating activities	**71.3**	57.9	39.4
Financing activities	**(1.5)**	(1.5)	(1.5)
Investing activities	**(28.6)**	(19.1)	(35.9)
Net assets of Discontinued Operations	**$ –**	$ 52.8	$ 51.8

(B) PENSION PLANS

The Company has both a defined benefit pension plan and a defined contribution plan which cover substantially all employees. The defined benefit pension plan provides pension benefits upon retirement based on length of service and final average earnings. Defined contribution benefits are determined by the value of contributions and the return on investment of these contributions.

The cost of pension benefits earned by employees is determined using the projected unit credit method and is expensed as services are rendered. This cost is actuarially determined and reflects management's best estimate of the pension plan's expected investment yields and the expected salary escalation, mortality rates, termination dates and retirement ages of pension plan members. The plan is funded as actuarially determined in accordance with regulatory requirements through contributions to a trust fund. The costs of defined contribution pension benefits are based on a percentage of salary.

The cumulative difference between the amounts funded and expensed is reflected as a deferred asset in the consolidated balance sheet.

At December 31, 1995, the market value of defined pension fund assets was $54.2 million (1994 – $57.8 million) and the accrued pension liability, as estimated by the Company's actuaries, was $38.1 million (1994 – $36.4 million).

In addition, one of the Company's unincorporated joint ventures has a defined benefit pension plan. At December 31, 1995, the market value of the Company's share of pension fund assets was $61.5 million (1994 – $53.6 million) and the Company's share of accrued pension liability, as estimated by the joint venture's actuaries, was $66.3 million (1994 – $54.9 million).

(C) RELATED PARTY TRANSACTIONS

During the year the Company sold approximately $9.7 million (1994 – $11.8 million) of natural gas to affiliates at market prices, none of which is included in accounts receivable at year-end (1994 – $0.6 million).

14. United States Accounting Principles and Reporting

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They differ from those generally accepted in the United States in the following respects:

(A) FULL COST ACCOUNTING

Under Canadian Generally Accepted Accounting Principles (GAAP), a ceiling test is applied to ensure that capitalized costs do not exceed the sum of estimated undiscounted, unescalated future net revenues from proven reserves less the cost incurred or estimated to develop those reserves, related production, interest and general and administration costs, and an estimate for restoration costs and applicable taxes.

Under the Full Cost method of accounting in the United States, costs accumulated in each cost centre are limited to an amount equal to the present value, discounted at 10%, of the estimated future net operating revenues from proven reserves, net of restoration costs and income taxes.

The Company has never incurred a write-down under the Canadian or U.S. standard.

(B) INCOME TAXES

Under Canadian GAAP the Company provides for potential future taxes using the deferred credit method under which tax provisions are established using tax rates and regulations applicable in the year the provision is recorded. These remain unchanged despite subsequent changes in rates and regulations.

In the United States, Statement of Financial Accounting Standards No. 109 (FAS 109), "Accounting for Income Taxes," requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. In estimating future tax consequences, FAS 109 generally considers all expected events including enacted changes in laws or rates. The application of FAS 109 decreased 1995 earnings by approximately $2.2 million.

(C) FOREIGN CURRENCY TRANSLATION

Long-term debt in foreign currencies was translated at the rate of exchange in effect at the end of the year. Unrealized exchange gains and losses arising on translation were deferred and amortized over the remaining terms of the debt. United States accounting principles require that such gains and losses be reflected in the period in which they arise.

(D) UNITED STATES EARNINGS

If the Consolidated Financial Statements had been prepared in accordance with generally accepted accounting principles in the United States the following adjustments would be required:

	1995	1994	1993
Net earnings as shown	**$ 110.2**	$ 100.5	$ 91.6
Impact of U.S. accounting principles:			
Income taxes - FAS 109	**(2.2)**	(33.0)	(15.7)
Foreign exchange	**–**	17.2	(7.6)
Net earnings according to U.S. GAAP	**$ 108.0**	$ 84.7	$ 68.3
Earnings per share			
Basic	**$ 1.44**	$ 1.14	$ 0.89
Fully diluted	**$ 1.43**	$ 1.14	$ 0.89

The adjustments under U.S. GAAP would result in changes to the Consolidated Balance Sheet of the Company as follows:

	As at December 31, 1995		As at December 31, 1994	
	As Reported	As Restated	As Reported	As Restated
Assets				
Current assets	**$ 226.1**	**$ 226.1**	$ 245.2	$ 245.2
Capital assets	**1,937.7**	**1,937.7**	2,017.7	2,017.7
Investments and other assets	**54.7**	**54.7**	94.7	74.7
	$ 2,218.5	**$ 2,218.5**	$ 2,357.6	$ 2,337.6
Liabilities and Shareholders' Equity				
Current liabilities	**$ 203.2**	**$ 203.2**	$ 240.5	$ 240.5
Long-term debt	**384.4**	**384.4**	561.8	561.8
Other liabilities	**47.0**	**47.0**	44.6	44.6
Deferred income taxes	**423.9**	**456.4**	448.8	479.0
Shareholders' equity	**1,160.0**	**1,127.5**	1,061.9	1,011.7
	$ 2,218.5	**$ 2,218.5**	$ 2,357.6	$ 2,337.6

15. Subsequent Event

In January 1996, the Company acquired Conwest Exploration Company Limited ("Conwest"). Conwest is engaged primarily in the exploration and production of oil and natural gas and has an investment portfolio and mining and hydro electric operations. AEC intends to dispose of the $165 million of non-oil and gas assets of Conwest.

Aggregate consideration for the purchase was $1,128.5 million, comprised of $351.9 million in cash, $539.0 million in attributed value in Common Shares of AEC and the assumption of $237.6 million of long-term debt. The cash portion of the consideration was financed from a new $375 million long-term debt facility with a syndicate of banks. The facility is fully revolving for a 364-day period with provision for extensions at the option of the lenders and upon notice from the Company. If not extended, the facility converts to a non-revolving reducing loan for a term of 6.5 years. The acquisition will be accounted for using the purchase method.

16. Segmented Information

	Exploration and Production			Transportation, Storage and Processing			Total		
	1995	*1994*	*1993*	*1995*	*1994*	*1993*	*1995*	*1994*	*1993*
Revenue	**$ 643.6**	$ 622.8	$ 499.8	**$ 149.7**	$ 166.7	$ 141.6	**$ 793.3**	$ 789.5	$ 641.4
Royalties	**63.5**	52.1	41.7	–	–	–	**63.5**	52.1	41.7
Revenue, net of royalties	**580.1**	570.7	458.1	**149.7**	166.7	141.6	**729.8**	737.4	599.7
Operating costs	**223.0**	223.1	194.9	**71.7**	80.0	70.0	**294.7**	303.1	264.9
Cost of gas purchased	**126.9**	83.0	35.4	–	–	–	**126.9**	83.0	35.4
Operating cash flow	**230.2**	264.6	227.8	**78.0**	86.7	71.6	**308.2**	351.3	299.4
DD&A	**131.6**	126.7	114.3	**21.1**	19.3	17.6	**152.7**	146.0	131.9
Operating income	**98.6**	137.9	113.5	**56.9**	67.4	54.0	**155.5**	205.3	167.5
Equity earnings	–	–	3.2	**3.2**	6.0	7.0	**3.2**	6.0	10.2
Divisional income	**98.6**	137.9	116.7	**60.1**	73.4	61.0	**158.7**	211.3	177.7
Less:									
Corporate G&A	**14.6**	16.3	12.8	**5.2**	2.3	4.8	**19.8**	18.6	17.6
Corporate DD&A	**2.3**	5.8	1.8	**0.8**	0.4	0.6	**3.1**	6.2	2.4
Interest and foreign exchange	**9.7**	35.1	4.7	**20.1**	13.6	8.1	**29.8**	48.7	12.8
Income taxes	**34.4**	32.2	36.6	**15.3**	23.4	19.1	**49.7**	55.6	55.7
Net Earnings Continuing Operations	**$ 37.6**	$ 48.5	$ 60.8	**$ 18.7**	$ 33.7	$ 28.4	**56.3**	82.2	89.2
Net Earnings Discontinued Operations (Note 4)							**53.9**	18.3	2.4
Net Earnings							**$ 110.2**	$ 100.5	$ 91.6
Identifiable assets	**$1,796.1**	$1,657.1	$1,592.4	**$ 422.4**	$ 429.7	$ 399.7	**$2,218.5**	$2,086.8	$ 1,992.1
Additions to capital assets and investments	**$ 239.9**	$ 283.5	$ 183.7	**$ 32.6**	$ 58.6	$ 69.3	**$ 272.5**	$ 342.1	$ 253.0

"Exploration and Production" includes conventional oil and gas production and marketing, International and Syncrude. "Transportation, Storage and Processing" includes pipelines, gas storage, natural gas processing and Syncrude utility operations.

Restated to reflect results from Forest Products as Discontinued Operations (Note 4).

Corporate assets have been allocated to the divisions.

Supplemental CONSOLIDATED FINANCIAL INFORMATION

(Unaudited)

FINANCIAL STATISTICS

	1995 Year	Q4	Q3	Q2	Q1	1994	1993	1992	1991
Net earnings ($ millions)	**110.2**	**9.3**	48.8	27.9	24.2	100.5	91.6	42.2	13.8
Per share ($) – Basic	**1.47**	**0.12**	0.65	0.38	0.32	1.36	1.23	0.53	0.12
– Fully diluted	**1.44**	**0.12**	0.62	0.38	0.32	1.34	1.21	0.53	0.12
Cash flow from operations ($ millions)	**270.7**	**59.0**	58.0	78.3	75.4	294.8	251.4	219.9	151.0
Per share ($) – Basic	**3.61**	**0.78**	0.77	1.05	1.01	4.07	3.52	3.11	2.15
– Fully diluted	**3.51**	**0.76**	0.74	1.02	0.99	3.88	3.33	2.98	2.04
SHARES									
Common shares outstanding (millions)	**75.5**	**75.5**	75.4	75.3	74.5	74.5	70.0	69.4	68.0
Average common shares outstanding (millions)	**75.0**	**75.5**	75.3	74.7	74.5	71.7	69.7	68.8	67.4
Price range, TSE ($ per share)									
High	**23.13**	**23.13**	21.50	22.25	20.00	22.75	23.63	17.00	16.88
Low	**16.38**	**19.75**	19.50	18.75	16.38	17.50	15.50	9.75	11.50
Close	**21.88**	**21.88**	20.38	20.50	20.00	17.88	18.50	16.25	12.50
Share volume traded									
Canadian exchanges (millions)	**41.9**	**11.7**	7.9	11.9	10.4	48.5	26.1	16.6	15.8
NYSE (thousands)	**455**	**313**	142	–	–	–	–	–	–
RATIOS									
Debt-to-equity									
Corporate	**25:75**					35:65	35:65	38:62	44:56
Exploration and production	**13:87**					21:79	21:79	26:74	37:63
Transportation, storage and processing	**64:36**					64:36	64:36	63:37	62:38
Debt-to-cash flow – Exploration and production	**0.8x**					1.2x	1.2x	1.7x	3.8x
Interest coverage	**4.8x**					4.8x	5.3x	2.1x	1.3x
Return on equity	**9.9%**					10.1%	9.9%	4.5%	1.0%
Return on assets	**5.9%**					6.1%	5.1%	3.2%	2.1%
Dividend ($ per common share)	**0.40**					0.40	0.35	0.35	0.33

DIVISIONAL CONSOLIDATED BALANCE SHEET

($ millions)	*Exploration and Production* 1995	1994	*Transportation, Storage and Processing* 1995	1994	*Forest Products* 1995	1994	*Total* 1995	1994
Assets								
Current assets	**$ 194.2**	$ 154.3	**$ 31.9**	$ 29.3	**$ –**	$ 61.6	**$ 226.1**	$ 245.2
Capital assets	**1,594.7**	1,489.1	**343.0**	333.4	**–**	195.2	**1,937.7**	2,017.7
Investments and other assets	**7.2**	13.7	**47.5**	67.0	**–**	14.0	**54.7**	94.7
Total	**$ 1,796.1**	$ 1,657.1	**$ 422.4**	$ 429.7	**$ –**	$ 270.8	**$ 2,218.5**	$ 2,357.6
Liabilities								
Current liabilities	**$ 179.5**	$ 155.3	**$ 23.7**	$ 29.8	**$ –**	$ 55.4	**$ 203.2**	$ 240.5
Long-term debt	**153.5**	232.8	**230.9**	229.6	**–**	99.4	**384.4**	561.8
Other liabilities	**45.4**	43.3	**1.6**	1.3	**–**	–	**47.0**	44.6
Deferred income taxes	**390.4**	358.6	**33.5**	41.4	**–**	48.8	**423.9**	448.8
Capital employed	**1,027.3**	867.1	**132.7**	127.6	**–**	67.2	**1,160.0**	1,061.9
Total	**$ 1,796.1**	$ 1,657.1	**$ 422.4**	$ 429.7	**$ –**	$ 270.8	**$ 2,218.5**	$ 2,357.6

Note: Corporate assets have been allocated to the divisions

CAPITAL INVESTMENT

($ millions)	1995	1994	1993	1992	1991
Conventional oil and gas					
Western Canada	**$ 193.0**	$ 237.4	$ 140.3	$ 63.5	$ 94.7
Argentina	**16.1**	22.6	–	–	–
Syncrude	**28.1**	18.9	36.0	8.3	15.8
Transportation, storage and processing	**30.5**	56.3	68.3	7.0	4.8
Forest products	**31.1**	29.6	8.6	8.7	12.4
Other	**3.3**	4.6	7.4	4.0	4.7
Total	**$ 302.1**	$ 369.4	$ 260.6	$ 91.5	$ 132.4

Corporate INFORMATION

BOARD OF DIRECTORS

Mathew M. Baldwin, B.Sc., Pet.Eng. [2,5]
President
Embee Consulting Ltd.
Edmonton, Alberta

Joan M. Donald [1,2]
Director and Officer
Parkland Industries Ltd.
Red Deer, Alberta

Richard F. Haskayne [1,3,4]
Chairman of the Board
NOVA Corporation
Calgary, Alberta

John C. Lamacraft [3]
Corporate Director
Toronto, Ontario

Hon. Donald S. Macdonald, P.C., C.C. [1,2,4]
Counsel
McCarthy Tétrault
Barristers and Solicitors
Toronto, Ontario

John E. Maybin [1,5]
Corporate Director
Calgary, Alberta

Stanley A. Milner, A.O.E., B.Sc., LL.D. [1,3,5]
President and Chief Executive Officer
Chieftain International, Inc.
Edmonton, Alberta

David E. Mitchell, O.C. [1,2,3,4,5]
Chairman
Alberta Energy Company Ltd.
Calgary, Alberta

Gwyn Morgan [2,5]
President and Chief Executive Officer
Alberta Energy Company Ltd.
Calgary, Alberta

Valerie A.A. Nielsen, P.Geoph. [3,4,5]
Oil and Gas Consultant
Calgary, Alberta

J. Harry Tims [2,5]
President and Chief Executive Officer
McTavish, McKay and Company Limited
Calgary, Alberta

H. Richard Whittall [1,3]
Corporate Director
Vancouver, British Columbia

SENIOR MANAGEMENT

Gwyn Morgan
President and Chief Executive Officer

Colin C. Coolican
Vice-President

Roger D. Dunn
Vice-President

Hector J. McFadyen
Senior Vice President

R. William Oliver
Vice-President

Drude Rimell
Vice-President, Corporate Services

John W. Stephure
Vice-President

John D. Watson
Vice-President, Finance and Chief Financial Officer

Kenneth S. Aberle
Director, Taxation

Derek S. Bwint
Treasurer

Brian C. Ferguson
Director, Corporate Relations and Corporate Secretary

Wayne G. Holt
General Counsel

Marcel F. Preteau
Director, Information Technology Services

Ronald H. Westcott
Comptroller

Richard H. Wilson
Director, Public Affairs

OFFICERS OF DIVISIONS

AEC OIL AND GAS

R. William Oliver
Executive Vice-President

John W. Stephure
Executive Vice-President

Dennis W. Cornelson
Senior Vice-President, Marketing

Randall K. Eresman
Vice-President

Guy C.L. James
Vice-President, Exploration

Allan F. Kiernan
Senior Vice-President, Production

Ronald H. Westcott
Vice-President, Finance

AEC PIPELINES

Hector J. McFadyen
President

Bernie J. Bradley
Senior Vice-President

J. Andrew Patterson
Vice-President, Finance

Robert A. Towler
Senior Vice-President, Business Development

AEC INTERNATIONAL

Roger D. Dunn
Executive Vice-President

Derek S. Bwint
Vice-President, Finance

COMMITTEES OF THE BOARD:

1 *Audit Committee*
2 *Environment, Health and Safety Committee*
3 *Human Resources and Compensation Committee*
4 *Nominating and Corporate Governance Committee*
5 *Pension Committee*

Corporate INFORMATION

CORPORATE OFFICE

#3900, 421 - 7 Avenue S.W.
Calgary, Alberta T2P 4K9
Phone: (403) 266-8111

REGISTERED OFFICE

#1200, 10707 - 100 Avenue
Edmonton, Alberta T5J 3M1
Phone: (403) 423-8333

TRANSFER AGENTS AND REGISTRARS (TRUSTEE)

Common Shares
10.50% Debentures (Trustee)
8.15% Debentures (Trustee)
Medium Term Note Debentures (Trustee)

The R-M Trust Company – Trustee
Calgary, Vancouver, Regina, Winnipeg, Toronto, Montreal, Halifax

Questions relating to share certificates, estate settlements, duplicate mailings, the dividend reinvestment and share purchase plan or other account information should be directed to R-M Trust's corporate trust offices in Calgary:

The R-M Trust Company
600 Dome Tower
333 - 7 Avenue S.W.
Calgary, Alberta T2P 2Z1
Phone: 1-800-387-0825
(toll free in Canada and Continental U.S.A.)

Chemical Mellon Shareholder Services LLC
New York

AUDITORS (FINANCIAL)

Price Waterhouse
Chartered Accountants
Calgary, Alberta

AUDITORS (OIL AND GAS RESERVES)

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

STOCK EXCHANGES

Common Shares are listed on the Toronto, Montreal, Vancouver and Alberta stock exchanges (symbol "AEC") and on the New York Stock Exchange (symbol "AOG").

MAJOR SUBSIDIARIES, AFFILIATES AND PARTNERSHIPS

A.E.C. Argentina S.A.	100%
AEC Energy Resources Ltd	100%
AEC Power Ltd. (50% voting)	66.7%
Alberta Oil Sands Pipeline Ltd.	100%
Alenco Gas Services Inc.	100%
Alenco Inc.	100%
Alenco Iroquois Pipelines Inc.	100%
Alenco Pipelines Inc	100%
Alenco Resources Inc.	100%
Conwest Exploration Company Limited (January 1996)	100%
Express Pipeline Inc.	100%
Express Pipeline Ltd.	50%
Iroquois Gas Transmission System, L.P.	6%
Pan-Alberta Resources Inc. (40% voting)	49.9%
Stealth Resources Limited	100%

MAJOR JOINT VENTURES

Ethane Gathering System		33.3%
Syncrude		13.75%
Alberta Energy Company Ltd.	10%	
AEC Oil Sands Ltd.	3.75%	
(75% of AEC Oil Sands Limited Partnership's 5%)		

ANNUAL INFORMATION FORM/FORM 40-F

AEC's Annual Information Form (AIF) is filed with securities regulators in Canada and the United States. Under the Multi-Jurisdictional Disclosure System (MJDS) introduced in 1991, AEC's AIF is filed as Form 40-F with the U.S. regulatory authority, the Securities and Exchange Commission.

ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS

Wednesday, April 3, 1996
at 3:00 p.m. local time

Westin Hotel
320 - 4 Avenue S.W.
Calgary, Alberta

Shareholders of Alberta Energy Company Ltd. are encouraged to attend. Those unable to do so are asked to sign and return the form of proxy mailed with this report.

ADDITIONAL INFORMATION

For additional investor relations information please contact Brian C. Ferguson, Director, Corporate Relations and Corporate Secretary, at the above Corporate Office address.

INTERNET ADDRESS

http://www.aec.ca

ABBREVIATIONS

bbl	*barrel(s)*
Bcf	*billion cubic feet*
Bcfd	*billion cubic feet per day*
Bcfe	*billion cubic feet equivalent*
boe	*barrel of oil equivalent*
B/D	*barrels per day*
BTU	*British thermal unit*
Mcf	*thousand cubic feet*
Mcfd	*thousand cubic feet per day*
Mcfe	*thousand cubic feet equivalent*
MMBLS	*million barrels*
MMBTU	*million British thermal units*
MMcf	*million cubic feet*
MMcfd	*million cubic feet per day*
NGLs	*natural gas liquids*

Printed in Canada